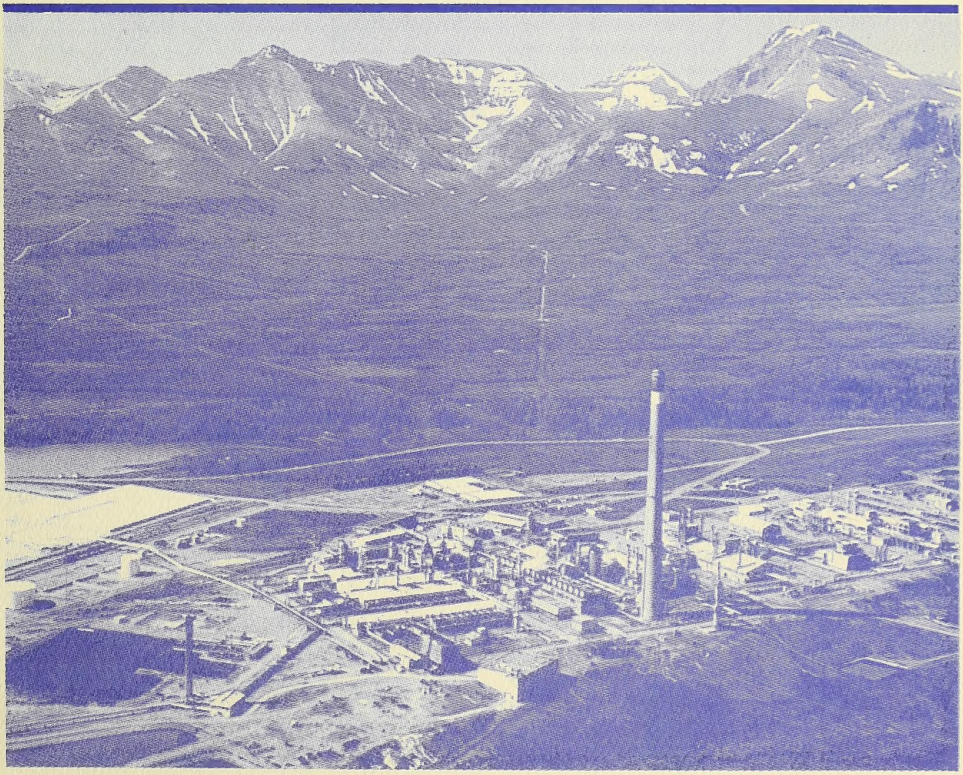
AL.2.1992-331 (Errata)
C.2 1856
CANADIANA
- 6 1992

REPORT 92-A

ERCB

Ultimate Potential and Supply of Natural Gas in Alberta



National Library of Canada Bibliothèque nationale du Canada

ERCB

Ultimate Potential and Supply of Natural Gas in Alberta

ENERGY RESOURCES CONSERVATION BOARD
ULTIMATE POTENTIAL AND SUPPLY OF NATURAL GAS IN ALBERTA

Report 92-A published June 1992

Published by:

Energy Resources Conservation Board
640 Fifth Avenue S.W.
Calgary, Alberta
T2P 3G4

Telephone: (403) 297-8311

Fax: (403) 297-7040

Cover Photo: Shell Waterton Gas Plant in the foothills of southwestern Alberta. Photo compliments of Shell Canada Limited.

TABLE OF CONTENTS

Chapter			Page
1	EXECUTIVE SUMMARY		1-1
	1.1	Background	1-2
	1.2	Alberta's Natural Gas Resource Base	1-2
	1.3	Economically Recoverable Reserves	1-3
	1.4	Reserves Growth Forecast	1-3
	1.5	Supply and Demand	1-4
	1.6	Unconventional Gas	1-4
	1.7	Impact of Technology	1-5
	1.8	Results and Conclusions	1-5
2	INTRODUCTION		2-1
	2.1	Conceptual Basis of Ultimate Potential Estimation	2-1
	2.2	History	2-2
	2.3	Scope and Format of this Report	2-3
	2.4	Industry Input	2-4
	2.5	Terminology and Abbreviations	2-4
	2.6	Units of Measure	2-4
	2.7	Effective Date of the Data	2-4
	2.8	Reader Comments	2-5
3	ULTIMATE GAS IN PLACE		3-1
	3.1	Introduction	3-1
	3.2	Data	3-2
	3.3	Stratigraphic Intervals	3-3
	3.4	Play Areas	3-3
	3.5	Determination of Average Gas In Place Per Section	3-5
	3.6	Gas Resource Categories	3-8
	3.7	Historical Drilling	3-9
		3.7.1 Success Rate Data	3-9
		3.7.2 Range of Successful Sections	3-12
	3.8	Range of Gas In Place	3-13
	3.9	Results	3-13
	3.10	Discussion	3-16
	3.11	Conclusions	3-17
4	ULTIMATE MARKETABLE GAS		4-1

TABLE OF CONTENTS (cont'd)

Chapter			Page
5	ECONOMICALLY RECOVERABLE RESERVES		5-1
	5.1	Introduction	5-1
	5.2	Database	5-2
		5.2.1 Resource Data	5-2
		5.2.1.1 Ultimate Potential	5-2
		5.2.1.2 Gas Play Areas	5-3
		5.2.1.3 Oil Play Areas	5-3
		5.2.1.4 Reservoir Recovery Factors	5-3
		5.2.1.5 Surface Loss	5-4
		5.2.1.6 Gas Composition	5-5
		5.2.1.7 Co-product Yields	5-5
		5.2.1.8 Success Rate	5-6
		5.2.1.9 Exploratory versus Development Drilling	5-7
		5.2.2 Exploration, Drilling and Production Costs	5-7
		5.2.2.1 Land, Geological and Geophysical Costs	5-8
		5.2.2.2 Drilling Depths	5-8
		5.2.2.3 Drilling and Completion Costs	5-8
		5.2.2.4 Drilling Density	5-9
		5.2.2.5 Production Start-up Time	5-12
		5.2.2.6 Production Profile	5-12
		5.2.2.7 Well Operating Costs	5-13
		5.2.2.8 Processing, Gathering and Completion Costs	5-13
		5.2.2.9 Flowline Costs	5-14
		5.2.2.10 Abandonment Costs	5-15
		5.2.3 Economic Assumptions	5-15
		5.2.3.1 Cost of Equity Capital	5-15
		5.2.3.2 Fiscal Regime	5-16
		5.2.3.3 Inflation Rate	5-16
		5.2.3.4 Price of Gas and Co-products	5-16
		5.2.3.5 Gas Equivalent of Oil	5-16
	5.3	Method of Analysis	5-16
		5.3.1 Gas Price versus Gas in place	5-17
		5.3.2 Gas and Oil in Each Section	5-18
		5.3.2.1 Zones in Each Section	5-18
		5.3.2.2 Deepest Well Depth	5-19
		5.3.2.3 Gas in Place per Section	5-19
		5.3.2.4 Oil in Place per Section	5-19
		5.3.2.5 Cost Allocation to Oil versus Gas	5-20
		5.3.2.6 Gas Price Required for Adequate Rate of Return	5-20

TABLE OF CONTENTS (cont'd)

Chapter			Page
		5.3.2.7 Zones Deeper Than Existing Wells	5-20
		5.3.2.8 Proven Reserves In Undrilled Formations	5-21
	5.3.3	Gas Price versus Economically Recoverable Reserves	5-21
	5.4	**Results and Conclusions**	5-21
	5.4.1	Summary of Results	5-21
	5.4.2	Conclusions	5-27
	5.5	**Critique of the Methodology**	5-27
	5.5.1	Stacked Zones	5-27
	5.5.2	Costs Attributable to Oil	5-27
	5.5.3	Resource Spread Throughout Play Area	5-28
	5.5.4	Seismic Reduction of Drilling Density	5-28
	5.5.5	Relatively High Costs Assumed	5-28
	5.5.6	Drilling Density Greater Than One Well per Section	5-28
	5.5.7	No Regard for Bitumen Drilling	5-28
	5.5.8	Co-product Pricing	5-29
	5.5.9	Full versus Half Cycle Economics	5-29
	5.5.10	Low Productivity Wells	5-29
	5.5.11	Overall Reliability of Results	5-29
6	**RESERVES GROWTH FORECAST**		6-1
	6.1	**Method of Analysis**	6-1
	6.2	**Historical Reserve Additions**	6-1
	6.3	**Reserve Additions per Section**	6-2
	6.4	**Drilling Activity Forecast**	6-2
	6.5	**Reserves Growth Forecast**	6-4
7	**SUPPLY AND DEMAND**		7-1
	7.1	**Gas Demand**	7-1
	7.2	**Gas Supply**	7-2
	7.2.1	Supply from Established Reserves	7-2
		7.2.1.1 Major Pool Study	7-3
		7.2.1.2 Cycling Pools	7-3
		7.2.1.3 Southeastern Alberta Shallow Gas Pools	7-4
		7.2.1.4 Solution Gas Pools	7-4
		7.2.1.5 Injection Pools	7-4
		7.2.1.6 Beyond Economic Reach Pools	7-5
		7.2.1.7 Deferred Pools	7-5
	7.2.2	Supply from Future Reserves	7-5
	7.2.3	Gas Supply versus Demand	7-6

TABLE OF CONTENTS (cont'd)

Chapter			Page
8	UNCONVENTIONAL GAS		8-1
	8.1	Introduction	8-1
	8.2	Tight Gas	8-1
	8.3	Coalbed Methane	8-2
	8.4	Reserves Potential	8-4
9	IMPACT OF TECHNOLOGY		9-1
	9.1	Introduction	9-1
	9.2	Evidence of Technological Change	9-1
	9.3	Specific Technological Advancements	9-4
		9.3.1 Drill Bit Technology	9-4
		9.3.2 Drilling Mud	9-4
		9.3.3 Horizontal Drilling	9-5
		9.3.4 Seismic	9-5
	9.4	Conclusions	9-6
10	CONCLUSIONS		10-1

Appendix			
A	GENERAL BULLETIN GB 90-11		A-1
B	ABBREVIATIONS AND TERMINOLOGY		B-1
	B.1	Abbreviations	B-1
	B.2	Terminology	B-2
C	INDUSTRY INPUT		C-1
	C.1	Formal Submissions	C-1
		C.1.1 Alberta Research Council	C-1
		C.1.2 NOVA Corporation of Alberta	C-2
		C.1.2.1 Total Conventional Potential	C-3
		C.1.2.2 Location of Reserves	C-4
		C.1.2.3 Supply	C-4
		C.1.2.4 Unconventional Reserves	C-5
		C.1.3 TransCanada PipeLines Limited	C-5
		C.1.4 Western Gas Marketing Limited	C-7
	C.2	Informal Input	C-9

TABLE OF CONTENTS (cont'd)

Appendix		Page
D	GEOLOGY OF STRATIGRAPHIC INTERVALS	D-1
	D.1 Paskapoo and Edmonton Interval	D-5
	D.2 Belly River Interval	D-11
	D.3 Chinook and Milk River Interval	D-19
	D.4 Medicine Hat Interval	D-23
	D.5 Cardium Interval	D-27
	D.6 Doe Creek Interval	D-33
	D.7 Dunvegan Interval	D-37
	D.8 Second White Specks Interval	D-41
	D.9 Base of Fish Scales Interval	D-47
	D.10 Viking Interval	D-51
	D.11 Basal Colorado Interval	D-59
	D.12 Mannville above Glauconitic Interval	D-63
	D.13 Glauconitic Interval	D-69
	D.14 Ostracod Interval	D-75
	D.15 Ellerslie Interval	D-81
	D.16 Cadomin Interval	D-87
	D.17 Nikanassin Interval	D-95
	D.18 Rock Creek Interval	D-101
	D.19 Nordegg Interval	D-107
	D.20 Baldonnel and Charlie Lake Interval	D-113
	D.21 Boundary Interval	D-117
	D.22 Halfway Interval	D-121
	D.23 Doig and Montney Interval	D-125
	D.24 Belloy, Kiskatinaw and Taylor Flat Interval	D-131
	D.25 Turner Valley Interval	D-137
	D.26 Shunda Interval	D-145
	D.27 Pekisko Interval	D-151
	D.28 Banff/Bakken Interval	D-157
	D.29 Wabamun/Crossfield Interval	D-165
	D.30 Nisku, Blueridge and Camrose Interval	D-173
	D.31 Leduc and Grosmont Interval	D-181
	D.32 Swan Hills and Slave Point Interval	D-191
	D.33 Sulphur Point Interval	D-199
	D.34 Gilwood, Granite Wash, Keg River, Zama and Muskeg Interval	D-203
E	GEOLOGICAL DATA AND RESULTS	E-1
F	DRILLING COST DATA	F-1

TABLE OF CONTENTS (cont'd)

Appendix			Page
G	CASH FLOW ANALYSIS RESULTS		G-1
H	MISCELLANEOUS MAPS OF ALBERTA		H-1
	H.1	Figure 1 — Modified-PSAC Areas	H-1
	H.2	Figure 2 — Gas and Oil Areas	H-1
	H.3	Figure 3 — Number of Gas Zones	H-1
	H.4	Figure 4 — Number of Oil Zones	H-1
	H.5	Figure 5 — Deepest Formation	H-1
	H.6	Figure 6 — Deepest Well Depth	H-2
	H.7	Figure 7 — Undrilled Sections	H-2
	H.8	Figure 8 — GIP per Section	H-2
	H.9	Figure 9 — OIP per Section	H-2
	H.10	Figure 10 — Gas Price	H-2
I	CUMULATIVE GAS IN PLACE VS INCREASING GAS PRICE		I-1
J	CUMULATIVE MARKETABLE GAS VS INCREASING GAS PRICE		J-1
K	HISTORICAL RESERVES GROWTH		K-1
	K.1	Booked Reserves	K-1
	K.2	Discovery well	K-2
	K.3	All wells	K-2
	K.4	Exploratory wells	K-2
	K.5	Oldest wells	K-2
	K.6	Drilled Sections	K-2
L	DEMAND AND SUPPLY FORECASTS		L-1

LIST OF TABLES

Table		Page
1.1	Alberta's Reserves of Marketable Gas at Year-end 1991	1-1
1.2	Alberta's Natural Gas Resource Base	1-2
3.1	Stratigraphic Intervals	3-4
4.1	Gas In Place and Marketable Gas – Yet to be Discovered	4-1
4.2	Gas In Place and Marketable Gas – Ultimate	4-1
4.3	Marketable Gas Potential by Gas Play Area – Medium Case	4-3
5.1	Reservoir Recovery Factors	5-4
5.2	Surface Loss	5-4
5.3	Gas Composition	5-5
5.4	Co-product Yields	5-6
5.5	Gas Well Success Rates	5-7
5.6	Development versus Exploratory Drilling	5-7
5.7	Drilling Rates	5-12
5.8	Well Operating Costs	5-13
5.9	Weighted Average Custom Processing, Gathering and Compression Fees	5-14
5.10	Capital Cost of Flowline	5-15
5.11	Average Abandonment Costs for Alberta	5-15
C.1	Coalbed Methane Resources – Alberta Research Council	C-2
C.2	Coalbed Methane Cost Groups – Alberta Research Council	C-2
C.3	Alberta Drilling and Reserves Growth – WGML Forecast	C-8
E.1	Success Rates and Percentage of Play Area Drilled	E-1
E.2	Drilled versus Undrilled Sections by Geologic Period	E-5
E.3	Gas In Place Assessment Medium Case	E-6
F.1	Drilling Costs – Area 1	F-1
F.2	Drilling Costs – Area 2	F-1
F.3	Drilling Costs – Area 3	F-2
F.4	Drilling Costs – Area 4	F-2
F.5	Drilling Costs – Area 5	F-2
F.6	Drilling Costs – Area 6	F-3
F.7	Drilling Costs – Area 7	F-3
F.8	Drilling Costs – Area 8	F-3
G.1	Capital Costs Attributed to Gas – Area 1 – Commercial Full Cycle	G-1
G.2	Capital Costs Attributed to Gas – Area 1 – Commercial Half Cycle	G-1
G.3	Capital Costs Attributed to Gas – Area 1 – Economic Full Cycle	G-2
G.4	Capital Costs Attributed to Gas – Area 1 – Economic Half Cycle	G-2
G.5	Capital Costs Attributed to Gas – Area 1 – No Royalty Full Cycle	G-3
G.6	Capital Costs Attributed to Gas – Area 1 – No Royalty Half Cycle	G-3

LIST OF TABLES (cont'd)

Table		Page
G.7	Capital Costs Attributed to Gas – Area 2 – Commercial Full Cycle	G-4
G.8	Capital Costs Attributed to Gas – Area 2 – Commercial Half Cycle	G-4
G.9	Capital Costs Attributed to Gas – Area 2 – Economic Full Cycle	G-5
G.10	Capital Costs Attributed to Gas – Area 2 – Economic Half Cycle	G-5
G.11	Capital Costs Attributed to Gas – Area 2 – No Royalty Full Cycle	G-6
G.12	Capital Costs Attributed to Gas – Area 2 – No Royalty Half Cycle	G-6
G.13	Capital Costs Attributed to Gas – Area 3 – Commercial Full Cycle	G-7
G.14	Capital Costs Attributed to Gas – Area 3 – Commercial Half Cycle	G-7
G.15	Capital Costs Attributed to Gas – Area 3 – Economic Full Cycle	G-7
G.16	Capital Costs Attributed to Gas – Area 3 – Economic Half Cycle	G-8
G.17	Capital Costs Attributed to Gas – Area 3 – No Royalty Full Cycle	G-8
G.18	Capital Costs Attributed to Gas – Area 3 – No Royalty Half Cycle	G-8
G.19	Capital Costs Attributed to Gas – Area 4 – Commercial Full Cycle	G-9
G.20	Capital Costs Attributed to Gas – Area 4 – Commercial Half Cycle	G-9
G.21	Capital Costs Attributed to Gas – Area 4 – Economic Full Cycle	G-9
G.22	Capital Costs Attributed to Gas – Area 4 – Economic Half Cycle	G-10
G.23	Capital Costs Attributed to Gas – Area 4 – No Royalty Full Cycle	G-10
G.24	Capital Costs Attributed to Gas – Area 4 – No Royalty Half Cycle	G-10
G.25	Capital Costs Attributed to Gas – Area 5 – Commercial Full Cycle	G-11
G.26	Capital Costs Attributed to Gas – Area 5 – Commercial Half Cycle	G-11
G.27	Capital Costs Attributed to Gas – Area 5 – Economic Full Cycle	G-12
G.28	Capital Costs Attributed to Gas – Area 5 – Economic Half Cycle	G-12
G.29	Capital Costs Attributed to Gas – Area 5 – No Royalty Full Cycle	G-13
G.30	Capital Costs Attributed to Gas – Area 5 – No Royalty Half Cycle	G-13
G.31	Capital Costs Attributed to Gas – Area 6 – Commercial Full Cycle	G-14
G.32	Capital Costs Attributed to Gas – Area 6 – Commercial Half Cycle	G-14
G.33	Capital Costs Attributed to Gas – Area 6 – Economic Full Cycle	G-14
G.34	Capital Costs Attributed to Gas – Area 6 – Economic Half Cycle	G-15
G.35	Capital Costs Attributed to Gas – Area 6 – No Royalty Full Cycle	G-15
G.36	Capital Costs Attributed to Gas – Area 6 – No Royalty Half Cycle	G-15
G.37	Capital Costs Attributed to Gas – Area 7 – Commercial Full Cycle	G-16
G.38	Capital Costs Attributed to Gas – Area 7 – Commercial Half Cycle	G-16
G.39	Capital Costs Attributed to Gas – Area 7 – Economic Full Cycle	G-16
G.40	Capital Costs Attributed to Gas – Area 7 – Economic Half Cycle	G-17
G.41	Capital Costs Attributed to Gas – Area 7 – No Royalty Full Cycle	G-17
G.42	Capital Costs Attributed to Gas – Area 7 – No Royalty Half Cycle	G-17
G.43	Capital Costs Attributed to Gas – Area 8 – Commercial Full Cycle	G-18
G.44	Capital Costs Attributed to Gas – Area 8 – Commercial Half Cycle	G-18
G.45	Capital Costs Attributed to Gas – Area 8 – Economic Full Cycle	G-18

LIST OF TABLES (cont'd)

Table		Page
G.46	Capital Costs Attributed to Gas – Area 8 – Economic Half Cycle	G-19
G.47	Capital Costs Attributed to Gas – Area 8 – No Royalty Full Cycle	G-19
G.48	Capital Costs Attributed to Gas – Area 8 – No Royalty Half Cycle	G-19
G.49	Capital Costs Attributed to Oil – Area 1 – Commercial Full Cycle	G-20
G.50	Capital Costs Attributed to Oil – Area 1 – Economic Full Cycle	G-20
G.51	Capital Costs Attributed to Oil – Area 1 – No Royalty Full Cycle	G-20
G.52	Capital Costs Attributed to Oil – Area 2 – Commercial Full Cycle	G-21
G.53	Capital Costs Attributed to Oil – Area 2 – Economic Full Cycle	G-21
G.54	Capital Costs Attributed to Oil – Area 2 – No Royalty Full Cycle	G-22
G.55	Capital Costs Attributed to Oil – Area 3 – Commercial Full Cycle	G-22
G.56	Capital Costs Attributed to Oil – Area 3 – Economic Full Cycle	G-22
G.57	Capital Costs Attributed to Oil – Area 3 – No Royalty Full Cycle	G-23
G.58	Capital Costs Attributed to Oil – Area 4 – Commercial Full Cycle	G-23
G.59	Capital Costs Attributed to Oil – Area 4 – Economic Full Cycle	G-23
G.60	Capital Costs Attributed to Oil – Area 4 – No Royalty Full Cycle	G-24
G.61	Capital Costs Attributed to Oil – Area 5 – Commercial Full Cycle	G-24
G.62	Capital Costs Attributed to Oil – Area 5 – Economic Full Cycle	G-24
G.63	Capital Costs Attributed to Oil – Area 5 – No Royalty Full Cycle	G-25
G.64	Capital Costs Attributed to Oil – Area 6 – Commercial Full Cycle	G-25
G.65	Capital Costs Attributed to Oil – Area 6 – Economic Full Cycle	G-25
G.66	Capital Costs Attributed to Oil – Area 6 – No Royalty Full Cycle	G-25
G.67	Capital Costs Attributed to Oil – Area 7 – Commercial Full Cycle	G-26
G.68	Capital Costs Attributed to Oil – Area 7 – Economic Full Cycle	G-26
G.69	Capital Costs Attributed to Oil – Area 7 – No Royalty Full Cycle	G-26
G.70	Capital Costs Attributed to Oil – Area 8 – Commercial Full Cycle	G-27
G.71	Capital Costs Attributed to Oil – Area 8 – Economic Full Cycle	G-27
G.72	Capital Costs Attributed to Oil – Area 8 – No Royalty Full Cycle	G-27
I.1	GIP Added at Various Gas Prices – Commercial Full Cycle	I-1
I.2	GIP Added at Various Gas Prices – Commercial Half Cycle	I-1
I.3	GIP Added at Various Gas Prices – Economic Full Cycle	I-2
I.4	GIP Added at Various Gas Prices – Economic Half Cycle	I-2
I.5	GIP Added at Various Gas Prices – No Royalty Full Cycle	I-3
I.6	GIP Added at Various Gas Prices – No Royalty Half Cycle	I-3
J.1	IMG Added at Various Gas Prices – Commercial Full Cycle	J-1
J.2	IMG Added at Various Gas Prices – Commercial Half Cycle	J-1
J.3	IMG Added at Various Gas Prices – Economic Full Cycle	J-2
J.4	IMG Added at Various Gas Prices – Economic Half Cycle	J-2
J.5	IMG Added at Various Gas Prices – No Royalty Full Cycle	J-3
J.6	IMG Added at Various Gas Prices – No Royalty Half Cycle	J-3

LIST OF TABLES (cont'd)

Table		Page
K.1	Reserves Growth Analysis Techniques	K-4
L.1	Gas Demand and Supply	L-2
L.2	Production from Major Gas Pools	L-3
L.3	Production from Cycling Pools	L-4
L.4	Production from Southeastern Alberta Shallow Gas Pools	L-6
L.5	Production from Major Solution Gas Pools	L-8
L.6	Production from Injection Pools	L-10

LIST OF FIGURES

Figure		Page
1.1	Gas Price vs Ultimate Potential – Commercial Full Cycle Scenario	1-3
1.2	Supply and Demand for Conventional Alberta Gas	1-4
2.1	Resource Triangle	2-1
3.1	Frequency of Average GIP per Section	3-6
3.2	Sections per Pool vs Cumulative Pools	3-6
3.3	Frequency vs Logarithm of GIP per Section	3-7
3.4	Median GIP per Section vs Time	3-7
3.5	Log-Log Plot of Median GIP per Section vs Time	3-8
3.6	Yearly Provincial Drilling Success Rates by Lahee Classification	3-10
3.7	Success Rate vs Distance from Reserves	3-11
3.8	Gas In Place by Geological Period – Medium Case	3-16
5.1	Drilling Costs – Area 1	5-10
5.2	Drilling Costs – Area 2	5-10
5.3	Drilling Costs – Area 3	5-10
5.4	Drilling Costs – Area 4	5-10
5.5	Drilling Costs – Area 5	5-11
5.6	Drilling Costs – Area 6	5-11
5.7	Drilling Costs – Area 7	5-11
5.8	Drilling Costs – Area 8	5-11
5.9	Gas Price vs Ultimate Gas In Place – Alberta	5-23
5.10	Gas Price vs Ultimate Potential – Alberta	5-23
5.11	Gas Price vs Per Cent of Future Gas Recoverable	5-24
5.12	Economically Recoverable Future Gas at $3.00/GJ	5-24
5.13	Per Cent of Future Gas Recoverable at $3.00/GJ	5-25
5.14	Gas Price vs Ultimate Gas In Place	5-26
5.15	Gas Price vs Ultimate Potential	5-26
6.1	Historical Reserves Growth	6-2
6.2	Reserves Growth vs Cumulative Sections	6-3
6.3	Reserves Growth Forecast	6-4
7.1	Forecast of Demand for Alberta Gas	7-1
7.2	Gas Supply Forecast	7-2
7.3	Supply and Demand for Alberta Gas	7-7
9.1	Historical Drilling Rates	9-2
9.2	Historical Drilling Costs in Waterton Field	9-2
9.3	Historical Reserve Additions per Well	9-3
9.4	Historical Drilling Success Rates	9-3

LIST OF FIGURES (cont'd)

Figure		Page
C.1	Annual Alberta Conventional Supply – NOVA	C-3
C.2	Modified Potter-Liddle Areas	C-4
C.3	Production Capacity of Alberta's Sedimentary Basin	C-6
C.4	Requirements vs Capabilities Scenarios – WGML	C-9
D.1	Paskapoo and Edmonton Interval	D-4
D.2	Belly River Interval	D-10
D.3	Chinook and Milk River Interval	D-18
D.4	Medicine Hat Interval	D-22
D.5	Cardium Interval	D-26
D.6	Doe Creek Interval	D-32
D.7	Dunvegan Interval	D-36
D.8	Second White Specks Interval	D-40
D.9	Base of Fish Scales Interval	D-46
D.10	Viking Interval	D-50
D.11	Basal Colorado Interval	D-58
D.12	Mannville above Glauconitic Interval	D-62
D.13	Glauconitic Interval	D-68
D.14	Ostracod Interval	D-74
D.15	Ellerslie Interval	D-80
D.16	Cadomin Interval	D-86
D.17	Nikanassin Interval	D-94
D.18	Rock Creek Interval	D-100
D.19	Nordegg Interval	D-106
D.20	Baldonnel and Charlie Lake Interval	D-112
D.21	Boundary Interval	D-116
D.22	Halfway Interval	D-120
D.23	Doig and Montney Interval	D-124
D.24	Belloy, Kiskatinaw and Taylor Flat Interval	D-130
D.25	Turner Valley Interval	D-136
D.26	Shunda Interval	D-144
D.27	Pekisko Interval	D-150
D.28	Banff/Bakken Interval	D-156
D.29	Wabamun/Crossfield Interval	D-164
D.30	Nisku, Blueridge and Camrose Interval	D-172
D.31	Leduc and Grosmont Interval	D-180
D.32	Swan Hills and Slave Point Interval	D-190
D.33	Sulphur Point Interval	D-198
D.34	Gilwood, Granite Wash, Keg River, Zama and Muskeg Interval	D-202

LIST OF FIGURES (cont'd)

Figure		Page
H.1	Modified-PSAC Areas	H-3
H.2	Gas and Oil Areas	H-5
H.3	Number of Gas Zones	H-7
H.4	Number of Oil Zones	H-9
H.5	Deepest Formation	H-11
H.6	Deepest Well Depth	H-13
H.7	Undrilled Sections	H-15
H.8	GIP per Section	H-17
H.9	OIP per Section	H-19
H.10	Gas Price	H-21
I.1	Gas Price vs Ultimate Potential for Gas In Place – Area 1	I-4
I.2	Gas Price vs Ultimate Potential for Gas In Place – Area 2	I-4
I.3	Gas Price vs Ultimate Potential for Gas In Place – Area 3	I-4
I.4	Gas Price vs Ultimate Potential for Gas In Place – Area 4	I-4
I.5	Gas Price vs Ultimate Potential for Gas In Place – Area 5	I-5
I.6	Gas Price vs Ultimate Potential for Gas In Place – Area 6	I-5
I.7	Gas Price vs Ultimate Potential for Gas In Place – Area 7	I-5
I.8	Gas Price vs Ultimate Potential for Gas In Place – Area 8	I-5
I.9	Gas Price vs Ultimate Potential for Gas In Place – Alberta	I-6
J.1	Gas Price vs Ultimate Potential for Marketable Gas – Area 1	J-4
J.2	Gas Price vs Ultimate Potential for Marketable Gas – Area 2	J-4
J.3	Gas Price vs Ultimate Potential for Marketable Gas – Area 3	J-4
J.4	Gas Price vs Ultimate Potential for Marketable Gas – Area 4	J-4
J.5	Gas Price vs Ultimate Potential for Marketable Gas – Area 5	J-5
J.6	Gas Price vs Ultimate Potential for Marketable Gas – Area 6	J-5
J.7	Gas Price vs Ultimate Potential for Marketable Gas – Area 7	J-5
J.8	Gas Price vs Ultimate Potential for Marketable Gas – Area 8	J-5
J.9	Gas Price vs Ultimate Potential for Marketable Gas – Alberta	J-6
K.1	Historical Reserves Growth Analysis Techniques	K-6

ACKNOWLEDGEMENTS

The Board would like to acknowledge the effort and dedication of the many people involved in preparing this report on ultimate potential and supply of Alberta gas. The major responsibilities for the various aspects of the report were carried out by:

• Report Coordination	Harvey Halladay
• Geological Study	Norbert Alwast Peter Cupido
• Economic Analysis	Georgette Habib
• Forecasting	Harvey Halladay Marie-Anne Kirsch
• Unconventional Gas	Tom Byrnes
• Impact of Technology	Mark Pinney

Significant contributions were provided by many others, in particular: **Geology** – Brenda Austin, Wayne Elsner, Don Schiefner, Earle Shirley and the summer students (Trevor Ryan, Robert Alway, Darryl Parry and Kirby Crowell); **Economics** – Collin Bennett and Jordan Linfitt; **Tight gas** – Andy Warren; **Computer mapping** – Wes Bader; **Database** – Judy Van Horne; **Graphics** – Jude Braganza, Gabriela Eibenschutz and Evelyn Topacio; and **Printing** – Herb Cullen, Rob de Grace and Ratan Kar.

1 EXECUTIVE SUMMARY

The Board's most recent major review of the ultimate potential for natural gas in Alberta was undertaken more than a decade ago. A considerable amount of drilling has taken place in the interim and much new information has been compiled. Advances have been made in gas industry technology and the economic environment has changed. Consequently, the Board has undertaken a detailed review of ultimate potential and supply of natural gas in Alberta as detailed in this report.

The Board's review of the province's ultimate potential for gas takes into consideration three important criteria: geological prospects, technology, and economics. Having regard for the uncertainties in estimating geological prospects, and predicting technological and economic change, the Board has adopted an estimate of 5600×10^9 m^3 (200 Tcf) as Alberta's ultimate potential for natural gas. The breakdown of this ultimate potential as of year-end 1991 is shown in Table 1.1. The Board also recognizes that there are large quantities of tight gas and coalbed methane in the province. These resources will become available with improved technology and economics. The Board's forecasts of the demand for and supply of Alberta gas suggest that conventional gas will be able to meet the demand until early in the next century. Thereafter, unconventional gas will likely be available to meet at least some portion, and perhaps all of the shortfall in supply of conventional gas.

TABLE 1.1 Alberta's Reserves of Marketable Gas at Year-end 1991[1]

Reserve Category	10^9 m^3 at 37.4 MJ/m^3	Tcf at 1000 Btu/cf
Initial Established	3 439	122
Cumulative Production	1 769	63
Remaining Established	1 670	59
Yet to be Established	2 161	77
Ultimate Potential	5 600	200
Remaining Ultimate Potential	3 831	136

The results and conclusions of the Board's work are summarized in the following sections and described in detail throughout this report.

---

1 Discrepancies are due to rounding.

1.1 Background

The ultimate potential for gas and the economics of recovering that potential are important to both Albertans and consumers of Alberta gas. These factors are key to forecasting the long term supply of Alberta gas and thus, the economic health and level of activity in Alberta's gas industry. Business and government planning require reasonable estimates of natural gas supply and knowledge of the economics of gas production.

In light of the long period of time since the last review of ultimate potential, the quantity of new information available, and the many changes in economic conditions, the Board has completed a series of detailed studies related to Alberta's ultimate potential and supply of natural gas. The Board requested input from the industry and received four formal submissions. The Board staff also received industry's advice through informal meetings with several gas producers and industry organizations.

1.2 Alberta's Natural Gas Resource Base

The Board's study of the province's conventional gas resource base includes a detailed analysis of historical drilling and geological information collected throughout the history of gas and oil development in the province. This study resulted in a range of estimates of ultimate potential. The Minimum case estimate represents a high degree of certainty and the Maximum case represents the Board's most optimistic view of supply and is subject to a great deal of uncertainty. The Medium case is the Board's best estimate at this time of the province's resource base for conventional gas. Table 1.2 presents all three estimates on both a raw gas in place and a marketable gas basis. The volumes shown in the table reflect the resource in place prior to any consideration of the portion of this resource which might be economically recoverable at various gas prices. Further references to ultimate potential in this chapter are to the Medium case.

Table 1.2 Alberta's Natural Gas Resource Base[2]

	Raw Gas In Place		Marketable Gas	
Case	10^9 m^3	Tcf	10^9 m^3	Tcf
Minimum	8 000	280	4 770	170
Medium	9 600	340	5 740	200
Maximum	12 700	450	7 570	270

2 Discrepancies are due to rounding.

1.3 Economically Recoverable Reserves

The Board has developed a methodology for estimating the portion of the future reserves in Alberta which will be recoverable at various gas price levels. This methodology was used in conducting a detailed, section-by-section analysis of the entire province. The analysis indicates that, using commercial full cycle economics, some 70% of the future resource could be economically developed at a gas price of $3.00/GJ. This estimate rises to some 87% given a gas price of $5.00/GJ. The Board also studied five other scenarios using alternative economic conditions. All of these scenarios produced more optimistic results than the commercial full cycle economics scenario. Any major advances in technology would also result in increased reserves.

Figure 1.1 shows gas price versus ultimate potential for the commercial full cycle economics scenario. As gas price increases, more gas can be economically recovered, thus increasing the ultimate potential. For illustrative purposes, a shaded area is also shown in the figure to illustrate where unconventional gas might be expected to play a role. However, the Board has done no specific quantitative analysis in this regard.

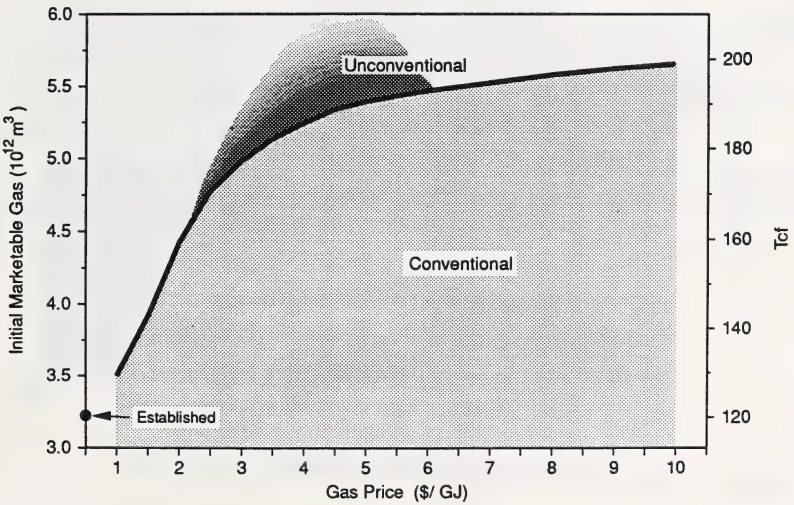


FIGURE 1.1 GAS PRICE vs ULTIMATE POTENTIAL
Commercial Full Cycle Scenario

1.4 Reserves Growth Forecast

The Board forecasts that drilling activity in Alberta will pick up through the mid to late 1990s and that reserves growth will increase accordingly. A fairly robust gas industry is expected to provide

substantial reserves growth for several years into the next century. Drilling activity and reserves growth will begin to decline as the quality of geological prospects declines, unless economic conditions allow the development of more marginal reserves.

1.5 Supply and Demand

The Board's forecast of the supply and demand for marketable gas in Alberta for the next 15 years is shown in Figure 1.2. Production is expected to increase throughout the 1990s and supply from conventional gas sources will be unable to meet demand by about 2002. Given the anticipated strong market growth and the Board's medium case estimate of ultimate potential, a very high level of industry activity would be required in order for supply to meet demand beyond this point. If economic circumstances are more favourable, the Board believes conventional reserves could meet foreseen demand well beyond that date.

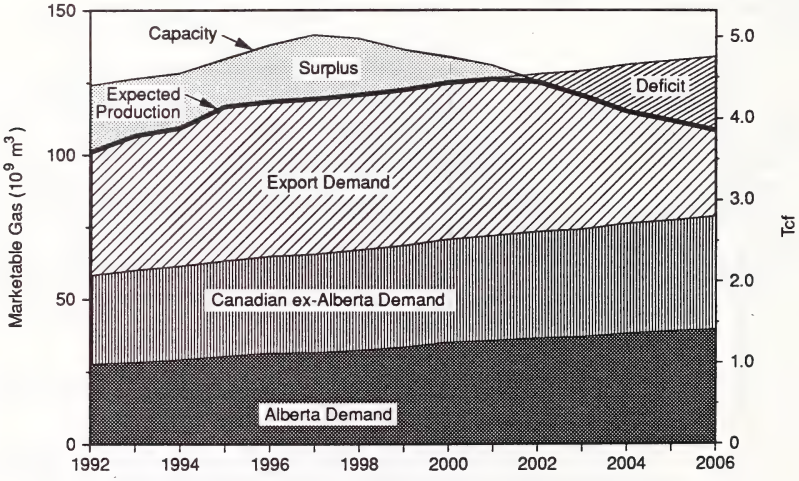


FIGURE 1.2 SUPPLY AND DEMAND FOR CONVENTIONAL ALBERTA GAS

1.6 Unconventional Gas

The Board has also studied the province's potential for production of unconventional gas, coalbed methane and tight gas. Although the unconventional resource size is very large, current economic conditions preclude the production of these resources using currently available technology. In light of the limited knowledge and experience with these resource types and the expectation that commercial production will not begin for several years, the Board has not attempted to estimate the resource size

or to forecast production levels. However, the Board does anticipate that with more favourable market and pricing conditions some production from unconventional sources could reasonably be expected to supplement the supply in the 15 year forecast period. Such conditions may well prevail when conventional gas sources are no longer able to meet the demand for Alberta gas as shown in Figure 1.2.

1.7 Impact of Technology

The Board anticipates that technological advancements will continue to improve the economics of gas exploration and production in Alberta. Improved economics will increase the amount of resource discovered in the province and increase the portion of that resource which can be recovered. The Board has not attempted to quantify the impact of technological advancements but, to the extent that they occur, the Board's reserve estimates and forecasts are considered to be conservative.

1.8 Results and Conclusions

The Board has included in this report much of the detailed data assembled in the course of conducting its geological, economic and other studies. This data is presented in the descriptions, tables and maps throughout the report and in the Appendices. Additionally, large detailed geological maps are provided with this report under separate cover. The Board trusts that this detailed information will be of use to the government, public and particularly the industry.

In conclusion, although Alberta's gas industry is currently in a depressed state, the Board expects the industry to become revitalized as prices firm up. A very healthy and economically viable gas industry is anticipated for many years into the future.

2 INTRODUCTION

2.1 Conceptual Basis of Ultimate Potential Estimation

Estimates of the ultimate potential for gas in Alberta and projections of the rate of development and production of that potential are required by the public, the government and the industry in making sound, long-term business and policy decisions. As suggested by its definition in Appendix B, ultimate potential has regard for three very important criteria: geological prospects, technology, and economics.

The geological sources from which the ultimate potential is to be drawn are comprised of a continuum of resource quality. This continuum has been referred to as the resource triangle[1] as illustrated in Figure 2.1. The volume of high quality resource at the top of the triangle is relatively small. As the quality of the resource decreases, toward the bottom of the triangle, the volume grows progressively larger.

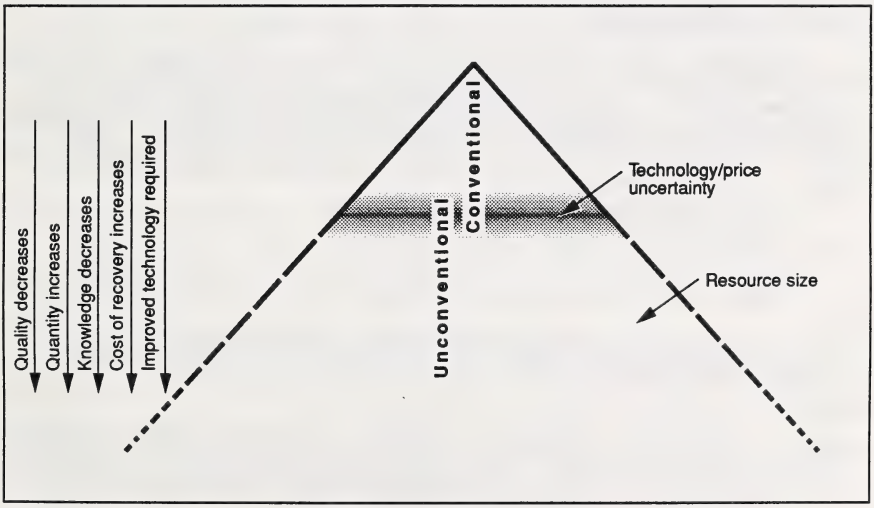


FIGURE 2.1 RESOURCE TRIANGLE

1 Gray, J. K., 1977. **Future Gas Reserve Potential, Western Canadian Sedimentary Basin:** Third National Technical Conference, Canadian Gas Association.

Conventional gas is that gas from geological sources where recovery is possible with technological improvements and prices that can be reasonably anticipated. Where extraordinary gas price increases or significant technological breakthroughs are necessary for recovery of the gas, and these changes are not reasonably foreseeable, the gas is termed unconventional. However, this does result in some overlap between conventional and unconventional gas in the area of the resource triangle where there is uncertainty respecting technology and price. Unconventional gas is characterized by limited commercial scale development and there is a focus on research and field experimentation. Limited commercial development generally means that there is limited knowledge and definition of the potential volume of the resource.

As discussed in Chapter 8, the main sources of unconventional gas in Alberta are tight gas and coalbed methane. Although it is often related to the very large volumes projected to exist in the thick sediments of the deep basin, tight gas also exists throughout the province in smaller, less economically attractive accumulations. Coalbed methane is a potential source of large quantities of natural gas and it too exists in a continuum of resource quality, the largest volumes being of poorer quality. Some high quality coalbed methane resources may in future prove to be as economically attractive as some reserves that are currently considered to be conventional. However, all coalbed methane is currently considered to be unconventional gas because of the uncertainty respecting the technology and economics of producing this gas.

Over the course of many years, improvements are made in technology and gas prices tend to increase. As discussed in Section 2.2, these changes result in the area of technology and price uncertainty moving downward and unconventional gas moving to the conventional category. Although estimates of ultimate potential have increased over time, the Board believes there is a finite limit to such increases. As alternative energy sources become more viable they will preclude the development of the lower quality gas resources.

2.2 History

The following discussion of the Board's historical estimates of ultimate potential will serve to illustrate the influence of the information base, technology, and economics on the estimation of ultimate potential.

The Board's first major review of ultimate potential took place in 1955 and resulted in an estimate of 1.7 to 2.8 $\times$ 10^{12} m^3 (60 to 100 Tcf). In the ensuing years, increased drilling provided much new knowledge of the province's potential for gas and the higher number, 2.8 $\times$ 10^{12} m^3, was adopted from 1964 to 1972. Markedly improved economics as a result of gas price increases resulted in a further increase in the estimate to 3.1 $\times$ 10^{12} m^3 (110 Tcf) in 1973.

The mid 1970s saw a tremendous increase in drilling activity in the province. The Board's last major review of ultimate potential was undertaken in the late 1970s. In ERCB Report 79-G[2], the Board

---

2 Energy Resources Conservation Board, 1979. **Ultimate Potential for Gas in Alberta.** ERCB Report 79-G. Calgary, Alberta.

increased its estimate of ultimate potential to a range of 3.7 to 3.9 $\times$ 10^{12} m^3 (130 to 140 Tcf) but recognized that with price and technological improvements the figure could go well beyond this level. Gas prices remained at a fairly high level throughout most of the 1980s and, in spite of the limited markets for Alberta gas, a great deal of drilling occurred in the province. The knowledge gained from this new drilling led the Board to increase its estimate of ultimate potential to 4.2 $\times$ 10^{12} m^3 (150 Tcf) in 1985 and again to 4.8 $\times$ 10^{12} m^3 (170 Tcf) in 1987.

It has been well over a decade since the Board's last major review of ultimate potential. Proposals to expand pipeline capacity to transport gas from Alberta to export markets prompted many questions about the long-term supply of gas. The Board believes that the current review of the prospects for gas supply from Alberta will assist in that process.

2.3 Scope and Format of this Report

The major focus of this report is on Alberta's ultimate potential for conventional gas. The report includes a detailed geological study of the resource base and an extensive economic analysis of the portion of that resource which is recoverable at various gas prices. Analyses of reserves growth, demand for Alberta gas and available supply are also included. Although quantitative estimates have not been made for unconventional gas, the Board does discuss it qualitatively and presents the quantitative estimates made by others. The Board has reviewed recent advances in technology but no specific projections of future advancements have been included in this report. No updated estimates of the ultimate potential for gas co-products are available as yet but the Board intends to update these estimates in future reports or as required.

Chapter 3 presents the geological study which the Board conducted in estimating the ultimate conventional gas in place. Minimum, Medium, and Maximum estimates have been included to reflect the combined uncertainties with respect to geological prospects, technology and economics. The Medium case estimate reflects the Board's current best judgement on each of these factors.

Using the Medium Case estimate of the ultimate resource available for development, the Board estimated the portion of the resource which might be recovered as marketable gas. Firstly, as discussed in Chapter 4, reservoir recovery factors and surface losses were applied to account for those volumes which cannot be recovered from the reservoir and processed to marketable gas. Secondly, as presented in Chapter 5, the Board conducted a detailed economic analysis to determine the portion of the resource which is economically recoverable at various price levels.

Chapter 6 presents the Board's forecast of reserves growth. The Board has an ongoing process whereby it periodically updates its forecasts of the demand for Alberta gas and the supply available to meet that demand. The Board considered those estimates to be current and adopted them for this report as presented in Chapter 7. The forecasts of supply and demand are shown for a fifteen year period.

Chapters 8 and 9 discuss unconventional gas and the impact of technology, respectively. Chapter 10 presents the Board's conclusions drawn from the several studies.

2.4 Industry Input

In October of 1990, the Board issued General Bulletin GB 90-11 (see Appendix A) requesting that industry provide input to the Board's review of ultimate potential and gas supply. Four companies made formal submissions to the Board in response to that bulletin:

- Alberta Research Council (ARC)
- NOVA Corporation of Alberta (NOVA)
- TransCanada PipeLines Limited (TCPL)
- Western Gas Marketing Limited (WGML)

The Board staff also met with several major gas producing companies and the Canadian Petroleum Association to discuss ultimate potential and future gas supply in Alberta. A summary of the information obtained in the submissions and the meetings with industry is included in Appendix C.

2.5 Terminology and Abbreviations

Some new terminology is introduced to describe the work done for this report. Definitions for these new terms and for many other terms are included in Appendix B. Many abbreviations are used for convenience throughout the report and they are also shown in Appendix B.

Chapter 9 of this report deals with unconventional gas. In all other chapters, the reference is to conventional gas unless otherwise stated.

2.6 Units of Measure

The data in this report is presented in metric units followed, where appropriate, with the imperial equivalent in brackets. In metric units, gas volumes are measured at the standard conditions of 101.325 kilopascals and 15 degrees Celsius. In imperial units, the standard conditions are 14.65 pounds per square inch absolute and 60 degrees Fahrenheit. Conversion from cubic metres to cubic feet is done using a conversion factor of 35.49373 cubic feet per cubic metre.

Some marketable gas volumes are shown on a 37.4 MJ/m^3 basis. The conversion from 'as is' to 37.4 MJ/m^3 basis is done by multiplying by a factor of 1.028. This factor reflects the current provincial average heating value for initial established marketable gas, some 38.44 MJ/m^3.

2.7 Effective Date of the Data

The studies described in this report have been conducted over the course of the nearly two years since the Board initiated its review of ultimate potential. Thus, the effective date of the data varies somewhat from one study to the next. For instance, data used in the geological analysis and the economics work is as of mid 1990 while that used in the reserves growth analysis is mid 1991. The

summary of ultimate potential contained in Table 1.1 of the executive summary uses the most current available reserve estimates, those for year-end 1991. The applicable effective date of the data for each study is indicated in the discussion of the study.

2.8 Reader Comments

In conducting its studies of Alberta's ultimate potential for gas, the Board has assembled a large amount of detailed data and information. Much of this data and the results of the various studies are presented in the various descriptions, tables and maps contained throughout this report and in the Appendices. Further, large detailed geological maps are included with this report under separate cover. Additional copies of these maps may be purchased separately.

With respect to the various maps, particularly the large geological maps, included with this report, the computer programs and systems are now in place to update these maps on a periodic basis. The reader is encouraged to contact the Board or its staff with comments as to the usefulness of this data and any interest in seeing periodic updates. Any other questions or comments concerning this report are also welcome. Comments should be directed to the Energy Resources Conservation Board, 640 - 5 Avenue S.W., Calgary, Alberta, T2P 3G4, Attention: Manager, Gas Department.

Step 5: **Gas Resource Categories** - Section 3.6

- subdivide play areas into sub-areas defined as Gas Resource Categories reflecting an estimated high, medium, or low to zero probability of finding gas.

Step 6: **Historical Drilling** - Section 3.7

- determine the ranges in historical drilling success rates for each gas resource category within each play area.
- multiply the total sections in each GRC by the minimum, maximum and medium historical drilling success rates to develop three estimates of the number of sections expected to contribute GIP in each gas resource category.

Step 7: **Range of Gas In Place** - Section 3.8

- multiply the three estimates of sections in the GRC by the average GIP per section for the area to develop three ultimate gas in place cases.
- the three ultimate gas in place cases reflect differing levels of confidence.

3.2 Data

The Board's Basic Well Data, Integrated Geological Data and Gas Reserves Systems were used to create a database of all relevant reservoir and well data on a section-by-section basis. This data includes well depths, geological tops and markers, fluid types, oil and gas reserve estimates, and well statuses. The section-by-section database was used to generate statistics, reports and computer maps for each stratigraphic interval. The database used in this study included all data available as of August 31, 1990.

In drawing the maps used to assess gas potential, the reserves were categorized according to the following hierarchy:

Section Category	Hierarchy
gas	highest priority
oil	
possible gas or oil	
wet	
tight	
penetrated but not evaluated	lowest priority

This hierarchy was applied to every drilled section in the province within each stratigraphic interval. For example, if a well was determined to have gas reserves for a particular stratigraphic interval, the section containing that well was categorized as a "gas section" even if other non-gas bearing wells were drilled in the same section. Non-gas bearing wells in the section result in reduced initial GIP values because the additional geologic information indicates a constrained acreage assignment.

3.3 Stratigraphic Intervals

A review of all possible hydrocarbon bearing zones was conducted and the Board recognized 89 zones as being capable of contributing to Alberta's ultimate GIP. The majority of these zones can be grouped into several stratigraphically equivalent intervals. The remainder are single or multiple zones that can be analyzed and represented as one stratigraphic interval. For example, the Swan Hills and Slave Point formations were treated as one interval because they are stratigraphically equivalent. Conversely, the Mannville Group above the Glauconitic and its equivalents were analyzed as a single interval, because they contain a complex distribution of reserves within a variety of individual sands. For this study, 36 stratigraphic intervals were selected as shown in Table 3.1.

The Board developed geologic models for each stratigraphic interval using published literature and ERCB compiled data.

Geologic and penetration maps for the entire province at a scale of 1 to 750 000 were created for each stratigraphic interval. The geologic maps were composites of available geologic data, including depositional and erosional edges, thermal hot lines and all pertinent structural features. Colour coded penetration maps showing a resource category for each section were generated based on the hierarchy described in Section 3.2. Each of these working maps gave a visual representation of gas and oil reserves and the distribution of historical drilling.

The geologic and penetration maps were combined to form composite maps for each stratigraphic interval. Appendix D contains page size representations of these composite maps at a scale of 1 to 5 000 000. For legibility, only the sections containing gas and oil are indicated. A further set of maps at a scale of 1 to 1 500 000 contains supplementary penetration data from the ERCB Basic Well Data file. These larger maps are included with this report under separate cover and may also be purchased separately.

3.4 Play Areas

Play area boundaries were established using the combined geologic and penetration maps and were based on the geologic models adopted for each stratigraphic interval. A play area was defined as a unique geographic area with similar geologic parameters, fluid types, drilling density or pool size. A stratigraphic interval may have one or more play areas. For example, the Doe Creek zone has only one play area due to relatively similar geologic conditions which occur within a restricted geographic area. In contrast, the Nisku stratigraphic interval has six play areas as it encompasses a variety of geologic conditions distributed over a larger geographic area. Some areas, where exploration has been unsuccessful to date, lack some or all of the requirements for a play area. In other studies, these areas have been referred to as conceptual or speculative. However, for the purposes of this study, such areas were not evaluated.

The geologic boundaries of the play areas were approximated on a township basis. This provided for use of the database in generating reserve and historical statistics for each area. All subsequent work in calculating gas potential was based on analysis of this data for individual play areas.

TABLE 3.1 Stratigraphic Intervals[1,2]

- Paskapoo and Edmonton
- Belly River (Wapiti)
- Chinook
- Milk River
- Medicine Hat
- Cardium
- Doe Creek
- Dunvegan
- Second White Specks
- Base of Fish Scales
- Viking (Bow Island, Cadotte, Paddy, Pelican)
- Basal Colorado
- Mannville Above Glauconitic
  (Colony, McLaren, Waseca, Sparky, General Petroleum, Rex, Lloydminster, Grand Rapids, Clearwater, Notikewin, Falher, Spirit River, Mountain Park, Undifferentiated Mannville)
- Glauconitic (Bluesky, Wabiskaw, Cummings, Moulton, Home)
- Ostracod
- Ellerslie (Gething, McMurray, Dina, Basal Quartz, Sunburst, Taber, Cutbank)
- Cadomin (Dalhousie)
- Nikanassin (Mist Mountain)
- Rock Creek (Swift, Sawtooth)
- Nordegg
- Baldonnel and Charlie Lake
- Boundary
- Halfway
- Doig and Montney (Spray River)
- Belloy
- Kiskatinaw and Taylor Flat
- Turner Valley (Elkton, Debolt, Mount Head, Livingstone)
- Shunda
- Pekisko
- Banff/Bakken
- Wabamun/Crossfield
- Nisku, Blueridge and Camrose
- Leduc and Grosmont
- Swan Hills and Slave Point
- Sulphur Point
- Gilwood, Granite Wash, Keg River, Zama and Muskeg

1 Zones in brackets are usually the stratigraphic equivalents.
2 Zones separated by "/" are formations and their members.

3.5 Determination of Average Gas In Place Per Section

The average volume of gas per section was estimated for each play area based on established reserves.

Initial GIP data was analyzed on a section basis for each non-associated, associated, and solution gas pool. A single average GIP per section (GIP/sec) was determined for each pool, that is, each pool was assigned a frequency of 1 such that each pool in a play area was weighted equally.

The number of pools discovered to date in any play area was assumed to be a representative sample of the entire population. The entire population included the proven plus undiscovered pools within that play area. For play areas where greater than thirty proven pools were present, a plot of frequency versus GIP/sec for any of the three gas types yields a log-normal distribution. This is consistent with the literature[1] which suggests that oil and gas reserves, as well as many other natural materials, occur in what, for practical purposes, can be described as a log-normal distribution. For play areas with less than 30 pools, a distribution type cannot be established.

Play Area 1 of the Mannville above Glauconitic stratigraphic interval exhibits a log-normal distribution. This distribution is shown in Figure 3.1. Greater than 50% of the distribution falls below the mean GIP/sec value. Thus, the mean of the sample is not representative of the entire population because the mean GIP/sec value (36.2×10^6 m^3) is skewed toward larger and better quality (higher GIP/sec) pools. Figure 3.2, a plot of average sections per pool versus cumulative pools discovered in the play area, indicates a gradual trend to smaller average pool size over time. This trend is expected to continue so the mean GIP per section value is not likely to be representative of future discoveries.

Figure 3.3 is the distribution shown in Figure 3.1 normalized by plotting the frequency versus the logarithm of GIP/sec. Irregularities in the lower GIP/sec segment of the distribution can be attributed to the use of standardized acreage assignments in calculating GIP for single well pools. This irregularity does not appear to be associated with selected rank magnitudes. The median of the raw data is equivalent to the mean of the normalized distribution and was considered more representative as the data is evenly distributed around this value.

Plotting the change in the cumulative median GIP/sec over time for the same data indicates that this value has not changed linearly with time. As the number of pools discovered increases, the rate of change of this value decreases. Figure 3.4 is a plot of the median values of GIP/sec for cumulative groups of 100 pools. The first data point represents the first 100 pools discovered, the second data point represents the first 200 pools discovered, and so on. The last data point is the median GIP/sec of the entire sample. As illustrated in Figure 3.4, median GIP/sec initially decreases rapidly because the majority of the largest and best quality pools have been discovered. As the play area matures and pool size continues to decrease, the rate of change becomes minimal such that, even if a large number of additional pools is anticipated, the change in median GIP/sec will be insignificant. This is illustrated in Figure 3.5, a log-log plot of median GIP/sec versus cumulative pools discovered.

---

1 McCrossan, R. G., 1969. **An Analysis of Size Frequency Distribution of Oil and Gas Reserves of Western Canada**. Canadian Journal of Earth Sciences, Vol. 6, pp. 201-211.

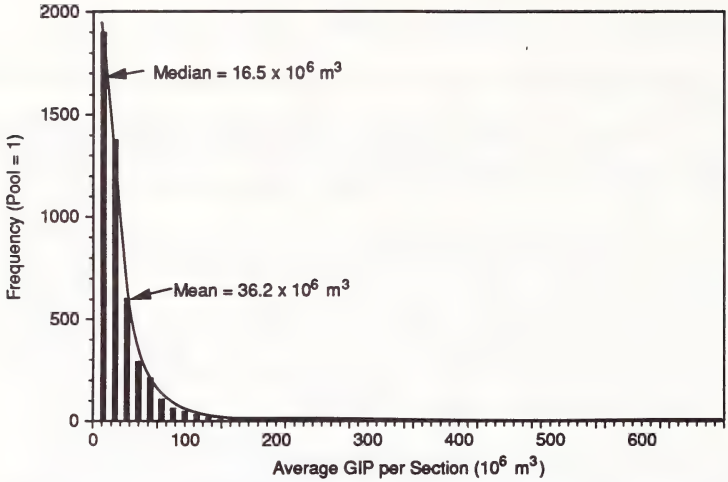


FIGURE 3.1 FREQUENCY OF AVERAGE GIP PER SECTION. Mannville Above Glauconitic Non-Associated Gas - Play Area 1

A frequency plot of average GIP per section shows that data is positively skewed. The mean value of the distribution is not representative because 70% of the distribution falls below the value. The median value is used for all calculations, as the data is evenly distributed about this point, as shown in Figure 3.3.

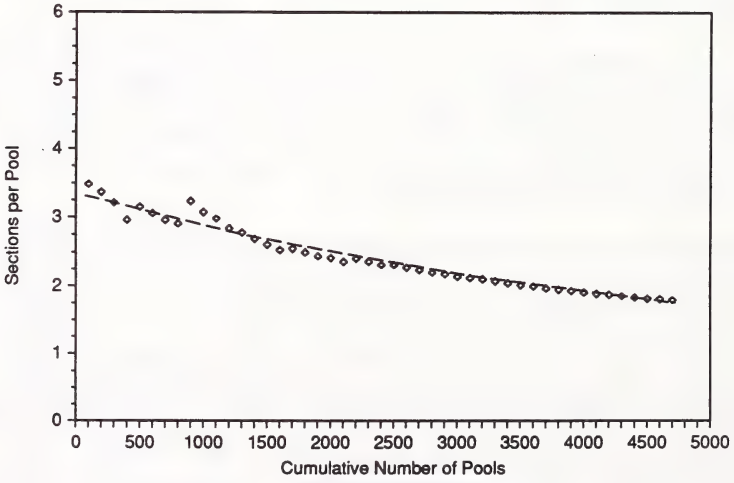


FIGURE 3.2 SECTIONS PER POOL vs CUMULATIVE POOLS. Mannville Above Glauconitic Non-Associated Gas - Play Area 1

Average number of sections per pool versus time (cumulative number of pools) decreases as a play area is developed. Porosity and pay thickness also tend to decrease on average with time. This does not preclude the discovery of large, good quality pools.

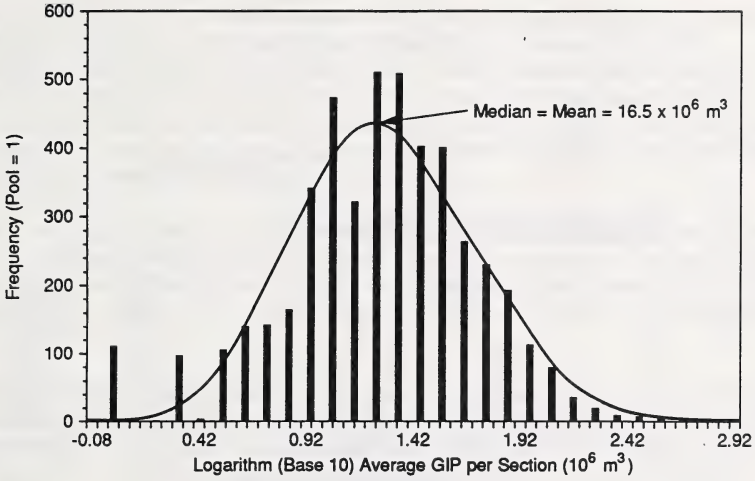


FIGURE 3.3 FREQUENCY vs LOGARITHM OF GIP PER SECTION. Mannville Above Glauconitic Non-Associated Gas - Play Area 1

The mean/median of the normal distribution that results is equal to the median of the raw data (Figure 3.1). This value is used for the calculations.

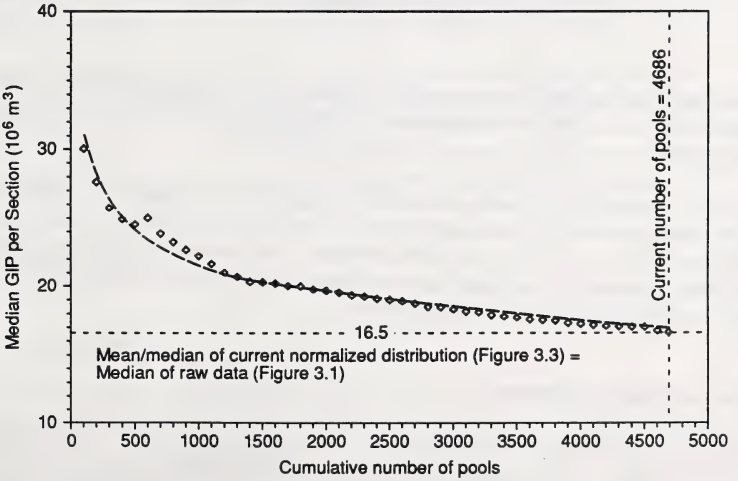


FIGURE 3.4 MEDIAN GIP PER SECTION vs TIME. Mannville Above Glauconitic Non-Associated Gas - Play Area 1

Median GIP per section versus time (cumulative number of pools) does not decrease linearly with time. As the number of pools discovered increases, the rate of change of median GIP per section value decreases. The cumulative data to date can be projected into the future as shown in Figure 3.5.

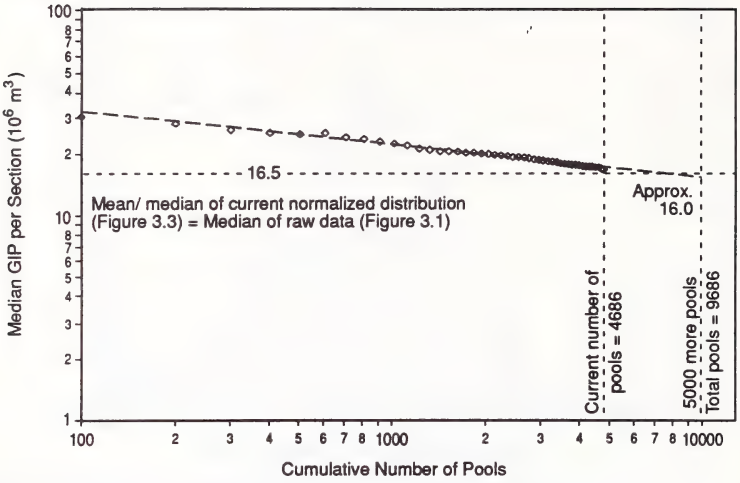


FIGURE 3.5 LOG-LOG PLOT OF MEDIAN GIP PER SECTION vs TIME.
Mannville Above Glauconitic Non-Associated Gas - Play Area 1

Data from Figure 3.4 plotted on a log-log scale, approximates a straight line. Projecting this line into the future shows that for an additional 5000 pools, the change in the median GIP per section value is small. Therefore, the median GIP per section value = 16.5 x 10^6 m^3 is a reasonable value to apply to future discoveries in this play area.

On the basis of this analysis, the median GIP/sec value of the sample distribution, Play Area 1 of Mannville above Glauconitic is representative of the current distribution, but can also be applied to future distributions as it is not expected to change significantly.

The Board concludes that the median of the distribution is the most representative value for GIP/sec and this value was used in all calculations where sufficient data was available. Where there was insufficient data to establish a representative distribution, the arithmetic average GIP/sec was used. The Board recognizes that this value, determined when the play area is immature and mainly large pools have been discovered, may be somewhat high.

3.6 Gas Resource Categories

The Board subdivided each play area into three distinct categories defined in terms of the probability of encountering gas. This probability was a function of geologic setting, reservoir type and distance from established reserves. The Board has called these sub-areas "Gas Resource Categories" (GRC). They equate roughly to classifications used by the American Potential Gas Committee (PGC).

The ERCB uses the Lahee Well Classification System (ERCB Informational Letter 86-4) to classify wells drilled in the province. This system is based primarily on the distance of wells from pre-existing reserves as well as on other geologic factors. Wells in close proximity to established reserves are classified as development in nature with more distant wells being classified as exploratory. Since GRCs and the Lahee well classification system are defined on a somewhat similar basis, the type of drilling expected to occur within each GRC can be described in terms of the Lahee classification. The three GRCs were defined as follows:

Gas Resource Category 1 describes areas where the geology and historical drilling suggest that future discoveries of in-place gas will be realized as a result of pool boundary expansion, primarily due to step out drilling. For this study, Lahee Classifications of Development and Outpost were considered to represent step out drilling. The analogous category used by the PGC is the "Unconfirmed Probable Resources".

Gas Resource Category 2 describes areas where geology and historical drilling indicate that future discoveries of in-place gas will be made primarily as a result of new pools being discovered on trend with proven pools. For this study, Lahee classifications of Outpost and New Pool Wildcat were used to represent GRC 2. The analogous category used by the PGC is the "Undiscovered Probable Resources".

Gas Resource Category 3 describes the remaining areas within the boundaries of a defined play area where a generally limited amount of historical drilling has resulted in minimal established reserves. In these areas, reserve additions are expected to be made as a result of true exploratory type discoveries. Lahee classifications of New Pool Wildcat and New Field Wildcat were used to represent GRC 3. The analogous category used by the PGC is the "Undiscovered Possible Resources".

Certain Lahee Classifications can be found in more than one GRC. For example, the Lahee classification of Outpost was used in both GRC 1 and 2 and this reflects the varying confidence in extending reservoir potential within different geologic environments.

The number of undrilled sections in each GRC was counted for use later in the procedure.

3.7 Historical Drilling

3.7.1 Success Rate Data

Post-1976 drilling statistics for the Lahee groupings described in Section 3.6 were taken from various issues of the Board's annual oil and gas industry statistics, the most recent of which was ERCB Report ST91-17[2]. Future drilling success rates for each play area were predicted from the variance in historical drilling success for specific Lahee groupings corresponding to the GRCs. The variance

---

2 Energy Resources Conservation Board, 1991. **Alberta Oil and Gas Industry Annual Statistics.** ERCB Report ST91-17. Calgary, Alberta.

was determined by examining frequency distributions of the historical drilling success for specific Lahee classifications. The procedure by which the data has historically been gathered does not allow further refinement of the success rates to the stratigraphic interval level. Therefore, for this study, the provincial rates calculated from ERCB historical data provide the basis for assigning success rates to all stratigraphic intervals. These success rates are shown in Figure 3.6.

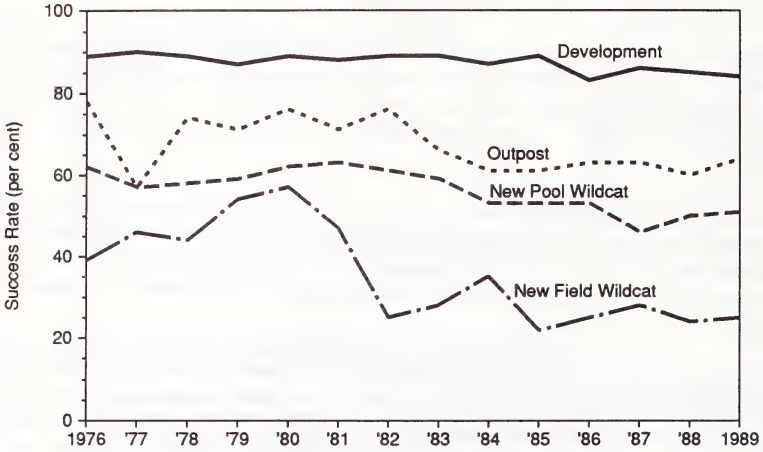


FIGURE 3.6 YEARLY PROVINCIAL DRILLING SUCCESS RATES BY LAHEE CLASSIFICATION
Percentage of all types of successful wells drilled from 1976 to 1989, from ERCB ST -17.

The Board also reviewed whether drilling activity levels and the corresponding success rate varied between oil and gas activity. Success rate is generally independent of oil versus gas drilling because success rates appear relatively constant for Development and Outpost wells, even though the proportion of oil and gas wells has varied. Also, New Pool Wildcat and New Field Wildcat rates, by virtue of their exploratory nature, are not affected by hydrocarbon type. In addition, success rates have remained relatively unchanged even though activity levels historically have been elevated through oil and gas price increases, drilling incentive and royalty programs, and increases in oil and gas demand.

As expected, drilling success rates varied with the distance from established reserves and this relationship varies for different geologic settings. The relationship between distance from reserves, drilling success rates and GRC type is shown schematically in Figure 3.7.

Provincial historical data indicates that drilling success for GRC 1 varies from 57-90%. The upper end of this range is affected by infill drilling at reduced spacing for conventional heavy oil and commercial bitumen. This type of drilling does not result in the addition of reserves to proven pools.

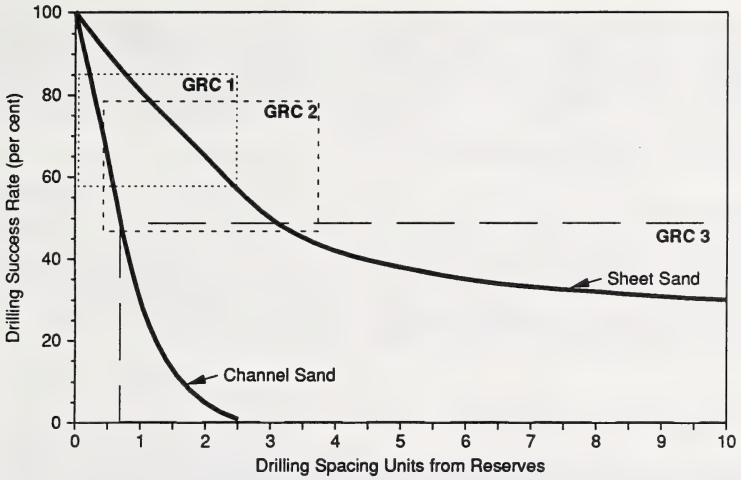


FIGURE 3.7 SUCCESS RATE vs DISTANCE FROM RESERVES
Superimposed on the GRCs are two schematic profiles of decreasing success rate with distance for a channel sand and a sheet sand. Zero distance (spacing units) represents proven reserves.

The range for GRC 1 was, therefore, adjusted to 57-85% to remove this influence of drilling in heavy oil areas.

Within GRC 2, drilling success varies from 46-79%. This range was used without adjustment because it appears to reflect an accurate distribution of success rates for this type of drilling.

Within GRC 3, drilling success varies from 22-63%. This range is influenced, to a great extent, by:

(1) drilling of successful prospects outlined by seismic data,
(2) non-targeted, successful gas zones, and
(3) a limited sample size.

To use this range, access to seismic data and knowledge of the specific target of New Pool Wildcat and New Field Wildcat wells is required. However, the ERCB has only limited access to this data. Using available data resulted in unreasonably large volumes of potential gas being assigned because the areas defined by GRC 3 were large and the prediction of future gas discoveries is less certain. Therefore, to estimate the volumes to be discovered in the large, diverse areas defined by GRC 3, the per cent of proven versus total drilled sections for the entire play area was used. Areas assigned to GRC 1 and GRC 2 were included in the calculation to anticipate their effect on the future success rate.

The resulting percentages vary from less than 1% to as much as 68%. The higher range is influenced by successes in large existing pools and, in many such areas, there was insufficient undrilled area to accommodate new pools of comparable size. The percentage in these areas was further modified to reflect this limitation in remaining available contiguous, undrilled sections. A pool-size cutoff, based on remaining contiguous, undrilled sections, was applied to the success ratio. This procedure results in reduction of the higher success rates to 48%.

The highest and lowest in success rates were used only within that specific play area to which they applied. This wide range could not reasonably be applied on a provincial basis. The highest success rate (48%) is only applicable to one foothills play area in which there is a high reliance on seismic data. The lowest rate (0.1%) was applied to areas backstepping from the subcrop of specific carbonate plays where success rates are very low. About 90% of the data fell within a range of 2 to 18% such that this range has been applied to GRC 3 on a provincial basis.

3.7.2 Range of Successful Sections

The Board calculated a Medium Case ultimate gas in place, assumed to be the most reasonable in light of current geologic data and technology. The success rate used for this Medium Case was the one judged to be the most representative for each GRC based on the geologic setting within the GRC. For example, within a sheet sand play such as play area 3 for the Cardium, the success rate for GRC 1 is 80%. Within a reef play, such as play area 3 of the Leduc, the success rate for GRC 1 is 70%. The success rates used to calculate undiscovered GIP were chosen within the ranges 57-85% for GRC 1, 46-79% for GRC 2 and less than 1 to 48% as specifically calculated for GRC 3. The success rates are summarized in Table E.1 in Appendix E.

The Board also calculated a Minimum and a Maximum Case for ultimate gas in place. The ranges in success rates of 57-85%, 46-79% and 2-18% for GRCs 1, 2 and 3, respectively were used in this calculation. The lowest value in the range for each GRC was used to calculate the Minimum Case and the highest value was used to calculate the Maximum Case. These cases reflect varying degrees of confidence in the number of sections in each play area which will be successful.

For each case, the number of undrilled sections expected to contain gas is the product of the number of potential sections available and the case specific success rate. These totals were subdivided by type (non-associated, associated or solution) on the basis of the division in established reserves. The historical division between gas types is expected to remain unchanged.

Stratigraphic intervals which contain either multiple formations and/or multiple pools within a single section require a variation in the estimation procedure. To ensure that multiple gas zones were accounted for (e.g. Belly River and certain Mannville play areas), a stacking ratio based on the average number of reservoirs per section plus a case specific success rate was subjectively determined for each area.

In addition, play areas with potential in the foothills belt also require a variation in the estimation procedure. These areas contain sections which were selectively drilled based on detailed seismic data.

The calculated success rates for GRC 3 generate excessively high numbers of potential sections, considering the large undrilled area. Therefore, in the foothills, an estimation of the number of potential structures along trend of the major pool fairways was required. Areas with no apparent structural closure were treated as areas of no potential.

Description of variations in the application of success rates to individual areas are fully outlined for each stratigraphic interval in Appendix D.

3.8 Range of Gas In Place

The following is a brief summary of the methodology for each stratigraphic interval:

(1) develop the play areas,
(2) determine an average GIP/sec for each gas type in each play area,
(3) subdivide the play area into GRCs,
(4) determine the potential sections in each GRC,
(5) multiply the potential sections by historical drilling success rates to estimate successful sections for the Minimum, Medium and Maximum cases,
(6) further subdivide each case by gas type,
(7) multiply these section subdivisions by their corresponding average GIP/sec to yield a range of undiscovered GIP estimates, and
(8) total the undiscovered GIP for each case in each play area.

Steps 1-8 were carried out for each stratigraphic interval and the results were summed for the range of undiscovered GIP.

A range of ultimate potential for GIP estimates was derived by adding the initial established GIP to the range of undiscovered GIP. In light of current geologic data and technology, the lower and upper values of this range, the Minimum and Maximum Cases, represent the limits of potential. They also represent the upper and lower degrees of confidence, respectively. However, current trends in historical drilling data as shown in Figure 3.6 suggest that the Medium Case value is most reasonable.

3.9 Results

The Minimum Case was calculated using the lowest success rate from the historical drilling data while the Maximum Case value was calculated using the highest. The Minimum Case is probably quite conservative as the historical rates do not indicate a decline to the lowest level in the near future, as illustrated in Figure 3.6. The Maximum Case is probably quite optimistic as current average success rates are not at this level.

The most likely undiscovered GIP value falls between the Minimum and Maximum Cases and is represented by the Medium Case which assumes continuation of historical success rate trends. It also recognizes that Alberta has not reached a mature state of development as it relates to gas. Gas

volumes were determined using the success rates for each play area, as summarized in Table E.1 in Appendix E. These were assumed to be most representative for future drilling within the respective play areas. There has been extensive drilling in Alberta, preferentially targeting shallow zones. This trend is expected to continue because drilling for shallower targets (e.g. Cretaceous) is usually more developmental in nature involving limited stepouts and, therefore, less risk. Drilling for deeper targets (e.g. Devonian) is usually more exploratory in nature, based primarily on seismic data and generally implies greater risk.

The percentage of undrilled acreage within the play areas increases dramatically from the Cretaceous to the Devonian. The Upper Cretaceous stratigraphic intervals contain an average of 45% drilled versus 55% undrilled sections, while the Devonian average is 12% drilled versus 88% undrilled sections. However, the total undrilled sections in the Upper Cretaceous is approximately twice that of the Devonian due to the Upper Cretaceous play areas spanning large portions of the province while the Devonian play areas are more limited in areal extent. The average drilled versus undrilled sections are summarized according to geologic period in Table E.2 in Appendix E.

With respect to future pool size, a general trend toward smaller pools is expected as discussed in Section 3.5. Although the majority of undiscovered GIP is expected to be found in new, smaller pools, it is also apparent that the probability of discovering larger pools increases with depth, contingent on the presence of contiguous undrilled sections within the play area.

The probability of discovering gas within GRC 1 is high due to the proximity to proven pools. The current distribution of reserves suggests there is still a significant volume of gas to be discovered in these areas. Few areas were designated as GRC 2 as most of the major trends have been delineated and fall within GRC 1. Therefore, the relative volume of undiscovered gas in this category is low compared to GRC 1. The Board's confidence in its estimates of undiscovered gas in GRC 3 is lower than in GRCs 1 or 2 due to poorer well control and lack of proprietary industry data. However, GRC 3 is expected to yield the highest volume of gas because of the large amount of undrilled area.

The portion of the GIP contained in each geologic period is illustrated in Figure 3.8 on an initial established, undiscovered and ultimate gas in place basis. Approximately 50% of the undiscovered potential falls within the carbonate portion of the stratigraphic column and will be found at greater depths. Within the carbonates, the Devonian Swan Hills in Play Area 1, which contains the recent Caroline Swan Hills discovery, is expected to contribute the largest incremental volume, 340×10^9 m^3 (12.07 Tcf).

The remaining undiscovered potential falls in the shallower clastic portion of the stratigraphic column. Within the clastics, the alluvial plain deposits of the Lower Cretaceous Ellerslie in south-central Alberta are expected to contribute the largest incremental volume, 221×10^9 m^3 (7.85 Tcf).

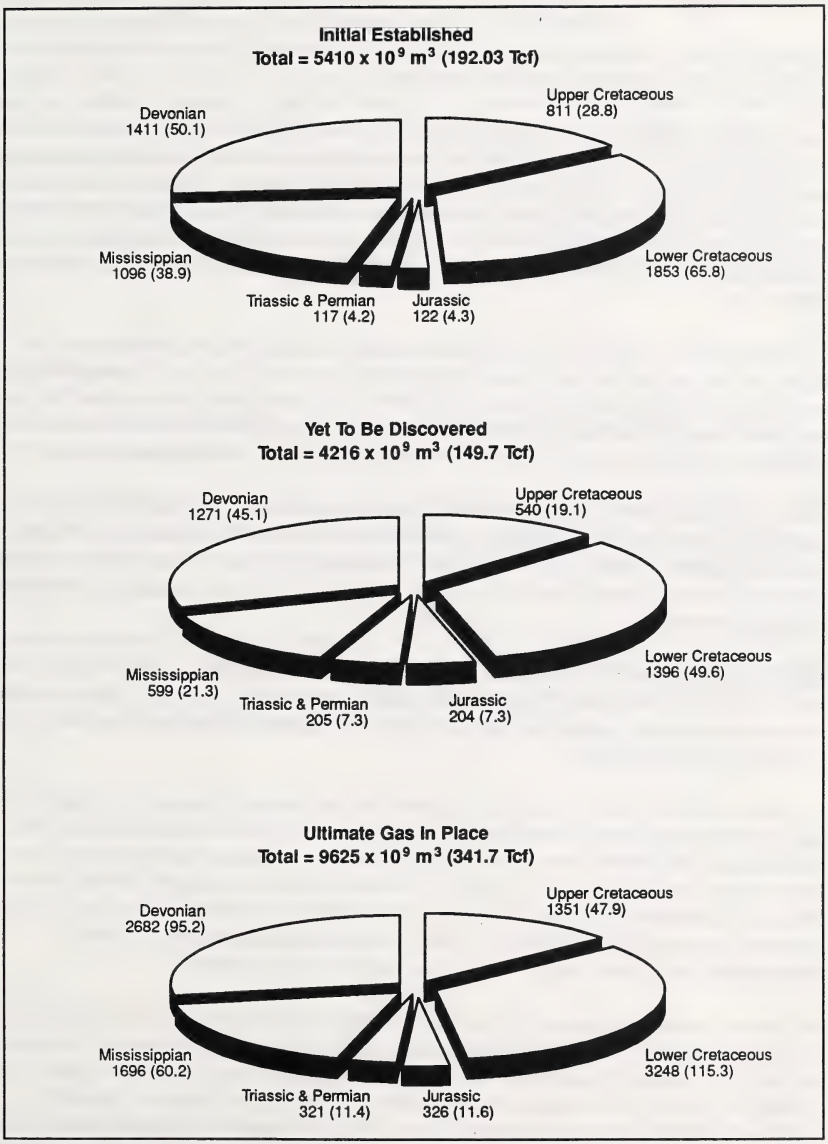


FIGURE 3.8 GAS IN PLACE BY GEOLOGICAL PERIOD - MEDIUM CASE

3.10 Discussion

The Board's geologic assessment indicates which play areas are likely to be the most attractive and contribute the most significant incremental volumes.

The Devonian is expected to provide an additional 1271 $\times$ 10^9 m^3 (45.1 Tcf) of undiscovered GIP. The majority of this gas is expected to be found in the deeper parts of the basin where drilling to date leaves large, contiguous, undrilled areas. These areas may possess reservoir characteristics similar to productive regions but require additional exploration to confirm their existence and, subsequently, delineate subtle traps. The most lucrative play areas are the Swan Hills carbonate bank in the Caroline area, the Leduc stratigraphic interval in the Obed/Windfall area and the Nisku bank in the Brazeau area.

An additional 599 $\times$ 10^9 m^3 (21.3 Tcf) of GIP is forecast to come from the Mississippian. The majority of this gas will be found in new, Turner Valley pools within the foothills as typified by the recent Ram (038-15W5) and other similar discoveries. The subcrop edges are densely drilled, and small incremental volumes are expected from step out drilling near proven pools. Play areas backstepping the subcrop edge lack structural closure and predictable porosity development.

Permian play areas are expected to offer limited opportunity, some 25 $\times$ 10^9 m^3 (0.9 Tcf) of GIP. The majority of this gas will be found in the Belloy around the Peace River Arch associated with extensional tectonics. Even though reserves are concentrated along the subcrop, Belloy porosity and permeability are wide-spread throughout much of the play area. This may indicate an elusive downdip trapping mechanism.

The Triassic is expected to contribute an additional 180 $\times$ 10^9 m^3 (6.4 Tcf) of GIP. The Halfway and Doig/Montney are the most lucrative stratigraphic intervals. Since shallower, oil-prone areas have been preferentially targeted and are more densely drilled, deeper gas-prone areas have experienced low activity levels.

An additional 204 $\times$ 10^9 m^3 (7.3 Tcf) is projected from the Jurassic. The majority of the gas will likely be found in the central Alberta Rock Creek play area. The Rock Creek in the Peace River Arch region is predominantly wet, however sand development is good and subtle traps may exist. The Nikanassin in the Deep Basin is expected to provide the largest incremental increase because many of the pools are insufficiently delineated. The Nordegg in the foothills has the second largest incremental increase with traps often associated with underlying Mississippian. Since the Mississippian is the primary target, Nordegg gas may have been overlooked.

The Lower Cretaceous is expected to contribute an additional 1157 $\times$ 10^9 m^3 (41.1 Tcf) of GIP. The Ellerslie is anticipated to contain the largest undiscovered volume with the Glauconitic the second largest. The Cadomin is expected to yield the largest incremental increase with the majority of gas to be found in the Spirit River channel play. Mannville sands above the Glauconitic, especially in northeastern Alberta, have been recent gas targets. Although the pools are generally small, they are economic to develop due to their proximity to each other. In this stratigraphic interval, gas is mainly

found in the Colony. The majority of undiscovered GIP for the Viking is expected from ongoing development of existing sheet sands which have not yet been fully delineated.

An additional 540 $\times$ 10^9 m^3 (19.1 Tcf) is anticipated from the Upper Cretaceous. The Cardium is expected to contain the largest undiscovered volume. It also represents the formation with the largest incremental increase. Potential is high in the foothills where there has been insufficient drilling to delineate Cardium structures that should exist as scour plays juxtaposed between the formation's provenance and its main sites of deposition. Additional shallow gas in southeastern Alberta (Milk River, Medicine Hat and Second White Specks stratigraphic intervals) will be discovered due to expansion along the edges of the major pools. The Belly River in northeastern Alberta, along its erosional edge, has potential for gas above the base of ground water protection but is often behind casing.

3.11 Conclusions

The Board's estimated range of undiscovered GIP is 2600 $\times$ 10^9 m^3 (90 Tcf) to 7300 $\times$ 10^9 m^3 (260 Tcf) representing the Minimum and Maximum Cases respectively.

The Medium Case value for the remaining undiscovered gas volume is estimated to be 4200 $\times$ 10^9 m^3 (150 Tcf). Table E.3 in Appendix E shows the estimated potential for each play area under the Medium Case which represents the most realistic scenario considering current geologic data and technology.

The initial established GIP used in this study was 5400 $\times$ 10^9 m^3 (190 Tcf) which was the ERCB's estimate as of mid 1990. Minimum, Medium and Maximum Case undiscovered GIP volumes, when added to this initial GIP volume, result in estimates of the ultimate gas in place of 8000 $\times$ 10^9 m^3 (280 Tcf), 9600 $\times$ 10^9 m^3 (340 Tcf) and 12 700 $\times$ 10^9 m^3 (450 Tcf).

4 ULTIMATE MARKETABLE GAS

Chapter 3 presents the Board's estimates of Alberta's ultimate gas in place. In order to convert these volumes of raw gas in the reservoir to marketable gas at the field processing plant exit, reservoir recovery factors and surface losses must be considered. The reservoir recovery factor accounts for volumes not recoverable from the reservoir due to production economics or other practical considerations. The surface loss factor accounts for volumes flared or used as fuel during the production process, volumes lost to shrinkage due to the recovery of natural gas liquids and sulphur, and volumes lost due to extraction of undesirable components such as carbon dioxide. Both raw and marketable gas volumes are expressed on a water free basis such that extraction of water need not be considered in the calculations.

In converting the gas in place figures to recoverable marketable gas, the Board assumed that the gas yet to be discovered in each of the gas play areas will have the same reservoir recovery factors and surface losses as the currently established reserves. Future technological advances or substantial improvements in gas prices could have some favourable impact on reservoir recovery factors or surface losses. However, this trend may well be offset to some degree as future reservoirs are expected to be of somewhat poorer quality than those found to date.

The volume weighted average reservoir recovery factor and surface loss was calculated for each gas play area. These factors were then applied to the gas in place estimates for the corresponding play areas. Table 4.1 presents a summary of the provincial gas in place and marketable gas reserves yet to be discovered for all three cases of resource potential. Table 4.2 presents the same information on an ultimate resource basis.

TABLE 4.1 Gas In Place and Marketable Gas - Yet to be Discovered

Yet to be Discovered	10^9 m^3			Tcf		
	Minimum	Medium	Maximum	Minimum	Medium	Maximum
Gas In Place	2 600	4 216	7 300	90	150	260
Marketable Gas	1 550	2 512	4 350	55	89	155

TABLE 4.2 Gas In Place and Marketable Gas - Ultimate

Ultimate	10^9 m^3			Tcf		
	Minimum	Medium	Maximum	Minimum	Medium	Maximum
Gas In Place	8 000	9 625	12 700	280	342	450
Marketable Gas	4 770	5 737	7 570	170	204	270

Table 4.1 shows that, for the province as a whole, some 2512 $\times$ 10^9 m^3 (89 Tcf) of marketable gas are yet to be discovered under the Medium Case. When added to the initial established marketable gas as of the mid 1990 study date, some 3224 $\times$ 10^9 m^3 (114 Tcf), this volume yields an ultimate potential for marketable gas of some 5737 $\times$ 10^9 m^3 (204 Tcf) as shown in Table 4.2. This estimate is the volume of marketable gas potentially recoverable from the resource in place without any consideration for exploration and development economics. Chapter 6 deals with the economic viability of recovering this gas.

Table 4.3 shows the initial raw gas in place, raw producible, and marketable gas for established, future and ultimate resource on a play area basis. Also shown are the reservoir recovery factors and surface losses which apply to both established and future gas.

TABLE 4.3 Marketable Gas Potential by Gas Play Area - Medium Case

Stratigraphic Interval	Established					Yet to be Discovered			Ultimate		
	Gas In Place	Recovery Factor	Producible	Surface Loss	Marketable	Gas In Place	Producible	Marketable	Gas In Place	Producible	Marketable
Paskapoo and Edmonton	1.73	54.8	0.95	6.2	0.89	4.10	2.25	2.11	5.83	3.19	3.00
Belly River	96.53	66.3	63.94	6.6	59.73	64.46	42.70	39.89	160.99	106.64	99.62
Chinook	0.96	75.9	0.73	11.7	0.64	4.81	3.65	3.22	5.77	4.38	3.87
Milk River	166.31	70.0	116.45	5.0	110.63	57.98	40.60	38.57	224.29	157.05	149.20
Medicine Hat	194.55	65.6	127.64	3.0	123.79	58.90	38.64	37.48	253.45	166.29	161.27
Cardium	257.30	47.0	120.85	26.5	88.87	253.35	119.00	87.51	510.65	239.85	176.38
Doe Creek	8.07	73.0	5.89	7.8	5.44	7.25	5.30	4.88	15.32	11.19	10.32
Dunvegan	18.09	71.5	12.92	8.9	11.77	32.89	23.50	21.40	50.98	36.42	33.16
Second White Specks	66.38	74.4	49.39	5.2	46.84	54.79	40.76	38.66	121.17	90.15	85.50
Base of Fish Scales	0.83	65.8	0.55	4.3	0.52	1.28	0.84	0.81	2.11	1.39	1.33
Viking	433.37	73.7	319.22	5.9	300.28	213.99	157.63	148.27	647.36	476.85	448.56
Basal Colorado	40.59	85.2	34.58	5.0	32.85	25.07	21.36	20.29	65.66	55.93	53.15
Mannville above Glauconitic	419.57	72.3	303.27	7.2	281.53	248.34	179.50	166.64	667.91	482.77	448.17
Glauconitic	437.86	72.4	316.97	8.8	289.03	352.68	255.31	232.80	790.54	572.27	521.84
Ostracod	29.33	79.0	23.17	10.0	20.85	43.63	34.46	31.02	72.96	57.62	51.87
Ellerslie	449.30	72.8	327.09	9.6	295.73	404.07	294.16	265.96	853.37	621.25	561.69
Cadomin	42.66	73.6	31.39	11.1	27.91	108.28	79.68	70.85	150.94	111.08	98.76
Nikanassin	12.75	74.8	9.54	13.0	8.30	48.45	36.26	31.53	61.20	45.80	39.82
Rock Creek	43.05	76.0	32.71	10.9	29.14	87.67	66.62	59.34	130.72	99.33	88.47
Nordegg	66.06	71.7	47.33	12.0	41.62	68.35	48.97	43.07	134.41	96.29	84.69

TABLE 4.3 (cont'd)

Stratigraphic Interval	Established					Yet to be Discovered			Ultimate		
	Gas In Place	Recovery Factor	Producible	Surface Loss	Marketable	Gas In Place	Producible	Marketable	Gas In Place	Producible	Marketable
Baldonnel and Charlie Lake	8.42	76.4	6.43	10.2	5.78	31.62	24.16	21.69	40.04	30.59	27.47
Boundary	2.67	51.9	1.38	13.5	1.20	4.83	2.50	2.17	7.50	3.89	3.36
Halfway	38.62	77.1	29.75	13.0	25.88	61.80	47.61	41.41	100.42	77.36	67.29
Doig and Montney	57.53	75.0	43.17	11.6	38.15	82.24	61.71	54.54	139.77	104.87	92.70
Belloy	9.78	76.6	7.49	14.0	6.44	24.50	18.76	16.13	34.28	26.24	22.57
Kiskatinaw and Taylor Flat	22.22	79.3	17.62	6.4	16.48	28.72	22.77	21.30	50.94	40.39	37.79
Turner Valley	892.76	78.0	696.00	23.4	533.25	411.56	320.85	245.83	1 304.32	1 016.85	779.07
Shunda	33.86	81.8	27.68	10.0	24.93	28.79	23.54	21.20	62.65	51.22	46.12
Pekisko	124.62	78.8	98.13	11.5	86.86	84.16	66.27	58.66	208.78	164.39	145.52
Banff/Bakken	22.90	74.9	17.15	10.5	15.34	46.09	34.51	30.88	68.99	51.66	46.22
Wabamun/Crossfield	234.03	72.4	169.51	35.7	108.94	293.67	212.71	136.70	527.70	382.21	245.64
Nisku, Blueridge and Camrose	131.87	69.1	91.10	25.4	67.93	237.58	164.12	122.38	369.45	255.22	190.30
Leduc and Grosmont	542.54	69.5	376.85	27.0	275.07	226.08	157.04	114.62	768.62	533.88	389.69
Swan Hills and Slave Point	410.16	67.7	277.76	35.4	179.45	440.84	298.54	192.87	851.00	576.30	372.31
Gilwood, Granite Wash, Keg River, Zama and Muskeg	78.04	77.1	60.12	14.3	51.55	18.80	14.48	12.42	96.84	74.61	63.96
Sulphur Point	14.21	66.1	9.39	27.6	6.80	53.94	35.66	25.81	68.15	45.05	32.60
Provincial Totals	5 409.52	71.6	3 874.30	16.8	3 224.07	4 215.56	3 019.18	2 512.47	9 625.08	6 893.48	5 736.55

5 ECONOMICALLY RECOVERABLE RESERVES

5.1 Introduction

In order to translate the resource potential into a reserves base that could be recovered in a reasonable time frame, it was critical to carry out an economic analysis. Such an analysis should recognize current and foreseeable fiscal regimes, development cost profiles, the importance of oil in the exploration for gas, and the variance in costs and geology for different areas of the province. The objective of the Board's economic analysis was to determine the volume of future gas resource potential that could be economically recoverable at different gas price levels.

In summary, the Board's section-by-section economic analysis involved:

(1) estimating the average amount of gas which might be discovered in the section,
(2) estimating the gas equivalent of the average amount of oil which might be discovered in the section,
(3) estimating the average depth of the well required to drill for oil and gas in the section,
(4) estimating the average land, geological, geophysical and drilling costs involved in developing the section,
(5) attributing the appropriate portion of the capital costs to oil,
(6) estimating the production profile for the gas,
(7) estimating the co-product yields for the gas,
(8) estimating the production costs including gathering and processing the gas,
(9) conducting a detailed cash flow analysis of the drilling, production and abandonment process to determine the gas price at which the section will yield a 15% rate of return, and
(10) totalling all section data to arrive at area and provincial totals of the amount of gas recoverable at various gas prices.

The province was divided into eight areas which represent regions where there is similarity in drilling depth, type of hydrocarbons and the physical characteristics of the resource. These areas are similar but not identical to the Petroleum Services Association of Canada's (PSAC) areas as published in its annual well cost studies and therefore will be referred to throughout this report as the "modified-PSAC areas". Much of the cost data utilized in this study as well as other parameters such as drilling success rates, exploratory versus development drilling splits, co-product yields, and pool recovery factors and surface losses were averaged within these areas. The modified-PSAC areas are shown in Figure 1 of Appendix H.

The economic analysis utilized detailed analysis of the ERCB's extensive databases of gas and oil industry information as well as a wide range of cost data assembled from various industry sources. The large amount of data used in the analysis and use of the computer in handling the complex manipulation of this data allowed the Board to deal with the more perplexing issues in estimating the portion of Alberta's resources which will be economically recoverable at various price levels. The analysis was done for every section (one square mile) of the province such that Alberta's economically

recoverable reserve at any given gas price was the total of all gas in those sections where the given price provided a reasonable rate of return.

It is important to note that the economic analysis was done on a time-independent basis. The objective was not to forecast the provincial supply of gas on an annual basis, but rather to study each modified-PSAC area to determine, at various gas prices, the volume of gas which could be economically recoverable given today's costs and technology. Thus, it was assumed that all the resources in the study area are developed at the same time.

This chapter provides a detailed description of the Board's economic analysis methodology as well as a brief discussion of the data used in the study. The results of the Board's study are also presented and certain conclusions are drawn from those results. Much of the cost data and detailed study results are presented in Appendices F through J.

5.2 Database

In its economic analysis, the Board has made extensive use of its own databases. Additionally, a considerable amount of data, most of which was cost related, was obtained from industry and the Alberta Department of Energy. Where specific information was not available, estimations or extrapolations were made from available data.

5.2.1 Resource Data

5.2.1.1 Ultimate Potential

As described in Chapter 3 of this report, the Board has completed a detailed study of the ultimate gas in place in Alberta. In Chapter 4, the portion of this resource which may be recoverable as marketable gas is discussed. The Board's estimate of the ultimate gas in place is some 9625×10^9 m^3 (340 Tcf) and converting this gas in place to marketable gas yields some 5737×10^9 m^3 (204 Tcf). The economic analysis attempts to determine the portion of this undiscovered potential which is recoverable at various gas price levels.

For illustrative purposes, Figure 2 in Appendix H shows the areas of the province underlain with oil, gas, or both oil and gas zones. As can be seen from the map, virtually the entire province is underlain with gas zones, the only notable exception being the northeastern portion of the province where no sedimentary deposits exist. The oil play areas also cover much of the province but are less widespread than the gas areas.

5.2.1.2 Gas Play Areas

In the Board's geological study, 112 gas play areas were identified in 36 geological horizons. These play areas have been described on computer files which can be used to create maps of the areas or to identify, for any section of the province, which play areas underlie the section. Figure 3 in Appendix H shows the areas of the province underlain with gas and is colour-coded to indicate the number of gas zones in each township.

5.2.1.3 Oil Play Areas

In 1988, the Board published a report[1] detailing its recent study of the ultimate potential for oil in Alberta and this report was later updated in 1990[2]. The oil study was done using a different methodology than that used for gas; play areas had not been defined as was done for this gas study. However, the Board has reviewed its oil work and created oil play areas, albeit in a more cursory fashion than was done for this gas study. Some 20 oil play areas have been identified in 14 geological horizons. Certain zones were grouped in establishing these oil play areas such that there is not a one-to-one correlation with the gas play areas.

The oil play areas include both light and heavy oil but do not include bitumen. Bitumen areas were excluded because there is only a limited amount of gas discovered in the exploration for and development of bitumen resources. Thus, very little of the capital costs incurred in gas ventures would be attributable to the search for bitumen.

Figure 4 in Appendix H shows the areas of the province underlain with oil and is colour coded to indicate the number of oil zones in each township.

5.2.1.4 Reservoir Recovery Factors

The average reservoir recovery factor for future reserves was calculated as the volume weighted average recovery factor for the initial established reserves in each gas play area. This assumes that the future pools in each area will have the same average reservoir recovery factor as the currently established pools. The total initial gas in place, the initial producible gas and the volume weighted average reservoir recovery factor are shown for each gas play area in Table 5.1.

---

1 Energy Resources Conservation Board, 1988. **Alberta Oil Supply, 1988-2003.** ERCB Report 88-E, Calgary, Alberta.

2 Energy Resources Conservation Board, 1990. **Alberta Oil Supply, 1990-2004, Update of ERCB 88-E.** ERCB Report 90-A. Calgary, Alberta.

TABLE 5.1 Reservoir Recovery Factors

Area	Initial Gas In Place (10^6 m^3)	Initial Producible (10^6 m^3)	Recovery Factor (%)
1	437 529	315 954	72.2
2	2 221 664	1 610 587	72.7
3	937 378	680 783	72.6
4	214 751	148 806	69.3
5	1 234 383	863 414	70.0
6	169 772	106 740	62.9
7	146 359	108 908	74.4
8	89 420	61 011	68.2
Alberta	5 451 256	3 896 203	71.5

5.2.1.5 Surface Loss

As with the reservoir recovery factor, the surface loss for future reserves was calculated as the volume weighted average surface loss for the initial established reserves in each gas play area. Surface loss is comprised of flared gas, fuel gas, and processing shrinkage and constitutes the difference between producible and marketable gas. The total initial producible gas, total initial marketable gas and the volume weighted average surface loss are shown for each area in Table 5.2.

TABLE 5.2 Surface Loss

Area	Initial Producible (10^6 m^3)	Initial Marketable (10^6 m^3)	Surface Loss (%)
1	315 954	202 450	35.9
2	1 610 587	1 251 605	22.3
3	680 783	634 777	6.8
4	148 806	140 738	5.4
5	863 414	758 063	12.2
6	106 740	101 448	5.0
7	108 908	99 476	8.7
8	61 011	50 158	17.8
Alberta	3 896 203	3 238 715	16.9

5.2.1.6 Gas Composition

An estimate of the average gas composition was required for future reserves in each of the eight modified-PSAC areas. This composition was required in order to estimate co-product yields and the portion of sweet versus sour gas. The volume weighted average composition for initial established reserves of producible gas in each gas play area was used for this purpose. This assumes that the future gas in each area will have the same average composition as the currently established gas. Table 5.3 shows the initial producible reserves for each area and the corresponding volume weighted average gas composition.

TABLE 5.3 Gas Composition

Area	H_2	He	N_2	CO_2	H_2S	C_1	C_2	C_3	iC_4	nC_4	C_5	C_6	C_7+
1	.00	.00	.77	4.51	12.07	72.75	4.18	1.41	.33	.63	.64	.49	2.14
2	.01	.02	1.04	3.75	7.32	77.15	5.50	2.23	.41	.73	.51	.33	.93
3	.00	.09	3.32	.69	.24	91.26	2.44	1.03	.22	.29	.19	.07	.08
4	.00	.06	3.52	.19	.00	93.50	1.64	.56	.12	.16	.11	.03	.03
5	.01	.03	2.80	1.43	.57	83.30	6.36	2.98	.46	.85	.50	.24	.41
6	.00	.01	.94	.87	.04	97.94	.14	.02	.00	.00	.00	.00	.00
7	.01	.07	2.63	1.15	.02	87.77	4.33	2.03	.32	.63	.37	.19	.41
8	.05	.03	2.07	2.86	1.28	82.11	6.07	2.75	.48	.94	.62	.29	.38
Alberta	.01	.04	1.96	2.46	4.20	82.19	4.73	2.00	.36	.63	.43	.25	.68

5.2.1.7 Co-product Yields

Average co-product yields were calculated by applying the estimated gas plant recovery efficiencies of 98%, 75%, 85% and 95% for sulphur, propane, butanes, and pentanes plus, respectively, to the gas composition estimates as discussed in Section 5.2.1.6. These co-product yields are expressed as tonnes of sulphur or cubic metres of liquid per million cubic metres of produced gas and are shown for each of the eight modified-PSAC areas in Table 5.4.

TABLE 5.4 Co-product Yields

Area	Co-product to Gas Ratios			
	Sulphur ($t/10^6$ m^3) Rec=98%	Propane ($m^3/10^6$ m^3) Rec=75%	Butanes ($m^3/10^6$ m^3) Rec=85%	Pentanes Plus ($m^3/10^6$ m^3) Rec=95%
1	250.40	79.57	63.24	266.65
2	125.27	103.50	62.22	119.08
3	3.45	40.03	23.13	20.07
4	0.04	21.39	12.92	10.46
5	8.77	122.29	62.67	68.56
6	0.62	0.85	0.35	0.27
7	0.37	80.36	43.90	55.81
8	20.71	120.68	72.79	82.06
Alberta	67.15	86.74	50.25	86.12

5.2.1.8 Success Rates

The economic analysis methodology assumes all wells were drilled as part of a hypothetical 100 well drilling program. Gas well drilling success rates were required in order to estimate what portion of the wells drilled in this 100 well program will actually incur production costs. These success rates were based on historical data for wells drilled in the years since 1980.

All wells in the database must be designated as either gas intent wells, oil intent wells, or wells drilled for some other purpose. For purposes of this study, wells which have only gas zones were defined as gas wells, wells with oil zones (whether or not they contain gas zones) were defined as oil wells, wells specifically identifiable as having been drilled for another purpose (bitumen, water, evaluation, injection, etc) were ignored, and the remaining wells were defined as unsuccessful wells. These unsuccessful wells were then divided into gas versus oil intent wells in the same proportion as the division between successful gas versus successful oil wells. The success rate is simply the successful gas wells divided by the total gas intent wells expressed on a percentage basis.

Success rates were determined separately for exploratory and development wells. The resulting success rates are shown in Table 5.5.

TABLE 5.5 Gas Well Success Rates

Area	Exploratory (%)	Development (%)
1	51	79
2	60	83
3	53	85
4	51	77
5	59	80
6	70	76
7	71	68
8	69	88

5.2.1.9 Exploratory versus Development Drilling

For each of the modified-PSAC areas, the Board examined the historical drilling data for the years since 1980 to establish the split between exploratory and development drilling. This split was required in the income tax calculations. The splits are shown in Table 5.6.

TABLE 5.6 Development versus Exploratory Drilling

Area	Development (%)	Exploratory (%)
1	34	66
2	56	44
3	85	15
4	71	29
5	67	33
6	92	8
7	60	40
8	46	54

5.2.2 Exploration, Drilling and Production Costs

The Board recognizes that its economic analysis will be sensitive to a wide variety of factors and it must be careful to select appropriate costs to make the results representative. It believes the following considerations meet that objective.

5.2.2.1 Land, Geological and Geophysical Costs

CPA statistics indicate that, during the period 1985-1990, land plus geological and geophysical (G&G) costs were approximately 35% of expenditures for exploratory and development drilling and field equipment. The Board used this relationship in estimating land and G&G costs. With the exception of 1987, land costs during the 1985-1990 period were about equivalent to G&G costs, and the Board's analysis assumed this relationship would continue.

5.2.2.2 Drilling Depths

For each of the eight modified-PSAC areas, the depth of all potentially productive formations was determined so as to get a range of well depths which were subsequently used in estimating well costs. The analysis assumes drilling depth intervals of 500 metres.

5.2.2.3 Drilling and Completion Costs

The Board based its drilling and completion cost estimates on the data published in PSAC's annual well cost studies. PSAC's drilling and completion costs include: drilling contract costs, service rig, road and site preparation, rig and miscellaneous transport, drilling fluids, logging (open hole and cased hole), drill stem testing, coring and core analysis, cement and cementing services, casing and attachments, tubing and attachments, special tool rental, bits, wellhead, stimulating and perforating, other equipment and services, engineering supervision and administration.

Within each of its seven study areas, PSAC identifies one or more locations where a significant number of wells have recently been drilled and where there is potential for active exploration in the near future. For each of these locations, a typical well is developed using average values for the wells in that area and the well cost is estimated based on current prices for contractors, services, material and equipment for that location.

Since the PSAC cost data is for a typical well drilled to a specified depth and since the analysis was based on 500 metre depth intervals, it was necessary to extrapolate the drilling costs to wells drilled to 500 metre intervals. This was accomplished by examining drilling and completion cost data submitted to the ERCB as part of applications under the Alberta Petroleum Incentives Program (APIP). Although the APIP data provides a relationship between well depth and drilling costs, albeit for the early 1980s, and this relationship was used to extrapolate the drilling cost data to the desired depth intervals. For those areas where the PSAC data included more than one typical well, the depth versus cost relationship was crosschecked using the PSAC data.

In order to broaden its database, the Board also used PSAC's drilling costs for oil wells. Some of these costs, e.g. stimulation and perforating, required downward adjustment and others, e.g. pumping equipment, were ignored as they related only to oil.

The PSAC data for Area 1 included data for two wells, one near Waterton and the other near Jumping Pound, for which the cost per metre drilled differed significantly. An average of these costs was used for this area. Winter drilling costs were used for Areas 6, 7 and 8 where winter drilling predominates. For the remaining areas, summer drilling costs were used along with summer drilling escalation costs per incremental metre drilled as per the APIP data.

For simplicity, the study did not use different cost data for exploratory versus development drilling. While it was recognized that in actuality there may be some difference for certain cost components such as for road and site preparation, the available database did not provide such a distinction.

The Board's study required data for drilled and abandoned wells as well as for drilled and completed wells. The data for both completed and abandoned wells is illustrated in Figures 5.1 through 5.8 and is shown in detail in Appendix F.

While the Board believes this drilling cost data is representative for each area of the province, undue reliance should not be placed on the data for any specific situation. Actual drilling and completion costs vary substantially, even for wells drilled to similar depths at locations within close proximity of each other. Thus, the data shown in this report should only be used as an approximation of typical well costs for the particular depth, geographic region and point in time.

5.2.2.4 Drilling Density

The normal drilling spacing unit for gas in Alberta is one well per section. However, the actual drilling density can be higher or lower depending on the drainage capability of the wells and the ability of geophysical techniques to detect where drilling will be successful.

Some high permeability reservoirs, such as those found in some parts of the Foothills, can be depleted with one well per two sections, while in very low permeability reservoirs, such as in the shallow zones of southeastern Alberta, several wells per section may be required. If seismic analysis is very accurate, it may be possible to find and produce all the pools in an area without drilling every section. Conversely, if seismic analysis is unreliable and, particularly, if very small pools are involved it may be necessary to drill more than one well per section to discover all pools in an area.

The Board's analysis assumes that, on average, one well per section will be required in all areas of the province except for modified-PSAC Area 1 (Foothills) where one well per two sections were assumed based on the larger drainage radiuses generally found in this area and on the high reliance on seismic work. Although much of Area 3 has been drilled at greater than one well per section, it has been assumed that future reserves in this and most other areas will be in deeper zones where higher reservoir permeability generally prevails.

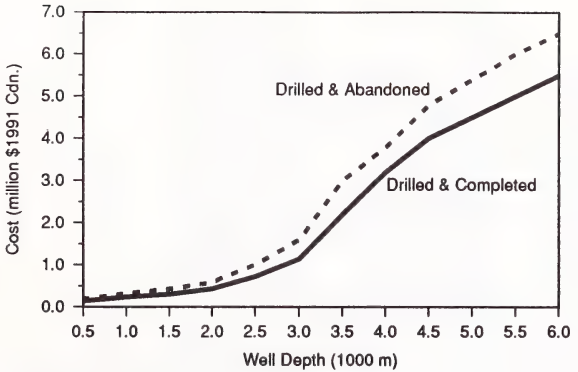


FIGURE 5.1 DRILLING COSTS - AREA 1

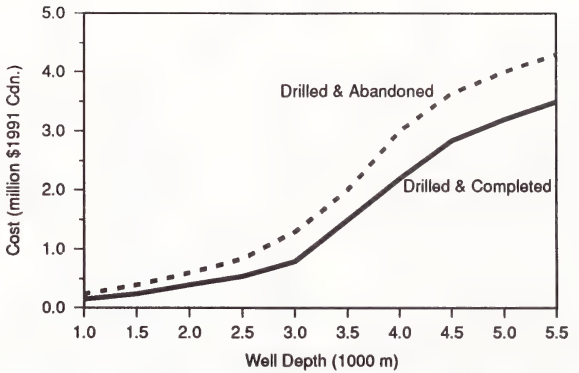


FIGURE 5.2 DRILLING COSTS - AREA 2

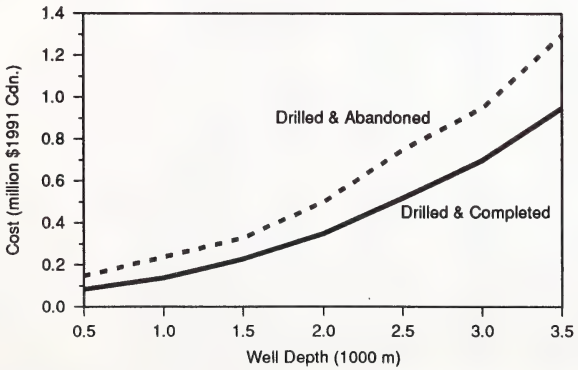


FIGURE 5.3 DRILLING COSTS - AREA 3

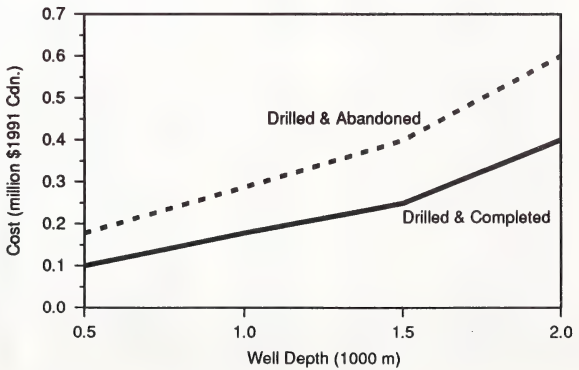


FIGURE 5.4 DRILLING COSTS - AREA 4

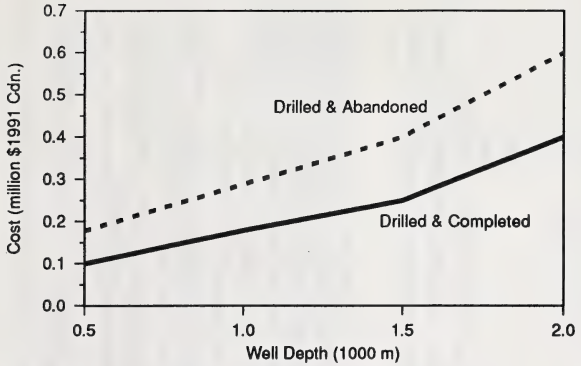


FIGURE 5.5 DRILLING COSTS - AREA 5

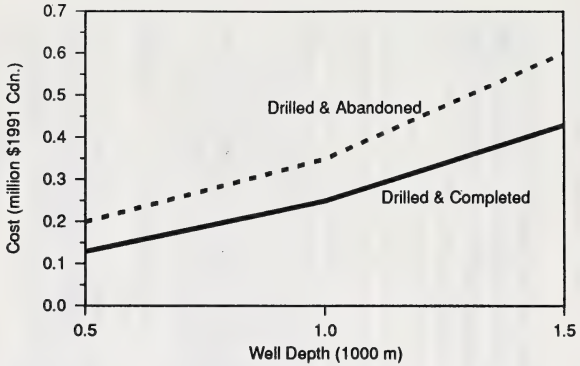


FIGURE 5.6 DRILLING COSTS - AREA 6

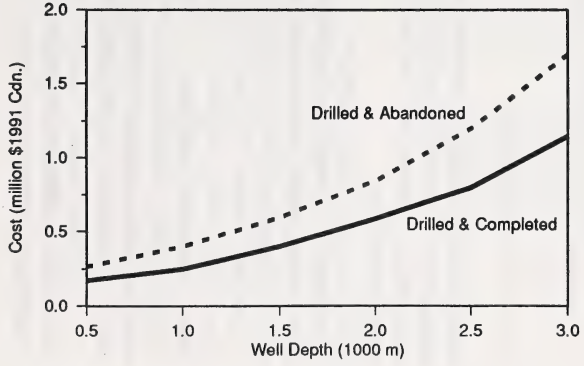


FIGURE 5.7 DRILLING COSTS - AREA 7

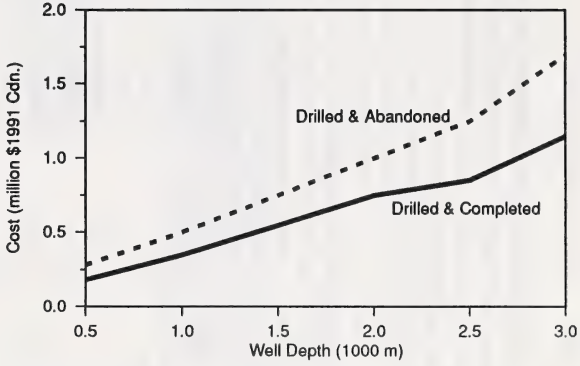


FIGURE 5.8 DRILLING COSTS - AREA 8

5.2.2.5 Production Start-up Time

The economic analysis was sensitive to the period when a well could be brought on production. It was estimated that one month would be required for site preparation and about a two-week period for flowline construction. The number of days required to drill a well at different depths in each of the eight modified-PSAC areas was derived from the most recent drilling rate data compiled by the ERCB and summarized in Table 5.7.

TABLE 5.7 Drilling Rates

Area	Well Depth (m)				
	<500 (m/day)	500-1000 (m/day)	1000-1500 (m/day)	1500-2000 (m/day)	>2000 (m/day)
1	97	59	49	117	117
2	116	150	173	156	94
3	150	228	195	183	126
4	125	220	224	224	224
5	119	189	205	170	124
6	97	156	120	-	-
7	114	146	104	133	109
8	114	98	123	90	87

5.2.2.6 Production Profile

The Board has done a cursory review of historical gas well production profiles in an attempt to determine a typical profile for use in this study. Unfortunately, there was an extremely wide variation in well life and in decline rates. For example, well life can range from as little as a few months to more than thirty years.

For purposes of this study, the Board used an initial rate-of-take of 1 unit of production per 3500 units of gas reserve (1/3500). Production was assumed to remain at this level until 50% of the reserve was depleted. Thereafter, a decline of 6% per year was assumed. This profile is probably somewhat high as a provincial average. However, it must be recognized that the purpose of this study is to establish the gas price at which a gas project becomes economic and that marginally economic wells are generally produced at higher rates. In Chapter 7, rates of take for established and future reserves of 1/7300 and 1/5000, respectively, have been used. These rates of take apply when there is a gas supply surplus and not all wells are being drilled on a threshold economics basis. The 1/3500 rate of take used here may well be appropriate in the later years of a longer-term forecast.

The economic analysis also assumed that there was a ready market for the gas and its co-products at market clearing prices.

5.2.2.7 Well Operating Costs

Well operating costs used in this study were determined through consultation with industry and the use of relevant operating cost data as reported in the Independent Petroleum Association of Canada's (IPAC) study entitled **IPAC Well Operating Cost Study** (January 1991).

Well operating costs are comprised of fixed and variable costs. Fixed costs are independent of production level and include items such as those associated with personnel involved in the actual daily operation of the gas well, lease rentals for access, administrative overhead charges, costs associated with lease and road maintenance, and other miscellaneous expenses. Variable operating costs are a function of level of production and consist of well treatment and maintenance, and expenses which are an extension of the former category but could separately be identified as workovers.

The operating cost data used in the economic analysis are summarized in Table 5.8.

TABLE 5.8 Well Operating Costs

Area	Fixed Operating Costs ($/well/month)	Variable Operating Costs ($/GJ)
1	3 500	0.05
2	1 900	0.043
3	215 (depth < 500 m)	0.01-0.03
	910 (depth > 500 m)	
4	700	0.03
5	1 000	0.05
6	990	0.03
7	1 980	0.04
8	1 980	0.04

The Board cautions that these estimates of operating costs are area averages and should not be applied to any specific situation. The estimates are based on the best available data but the actual costs experienced by individual operators may differ significantly, even for similar wells in the same area of the province.

5.2.2.8 Processing, Gathering and Completion Costs

It was assumed that third party custom processing fees generate an adequate return to the plant owner. These fees were used in this analysis to estimate processing costs as well as for purposes of calculating the Gas Cost Allowance (GCA). This eliminates the need for detailed modelling to estimate the size and type of new plants and, subsequently, the capital and operating costs for such plants. Third party processing fees were based on a utility concept of fee scheduling and provide for

payments to be made to a facility owner for initial investment (depreciation), interest charges on debt, return on equity, operating costs and income taxes.

There are more than 600 gas processing plants in Alberta, the majority of which provide custom processing for third party gas. Although the fees charged for custom processing are not publicly disclosed, the Board asked a number of plant operators to provide processing fee data and, where applicable, to include gathering and compression data. The Board received processing, gathering and compression fee data for approximately 100 plants throughout the province, some processing sweet and others sour gas. Where operators only reported processing charges, a gathering charge of $\$0.25/10^3\ m^3$ per kilometre over an average distance of 6 kilometres and a compression cost of $5.00 to $9.00 per $10^3\ m^3$ were used. Since these charges were provided to the ERCB in confidence, only the average fee for each of the modified-PSAC areas can be disclosed.

The fee used in the analysis was a weighted average of the sweet versus sour processing fees. The average was weighted on the basis of the initial established reserves of sweet versus sour gas for each of the eight areas. This data is presented in Table 5.9.

TABLE 5.9 Weighted Average Custom Processing, Gathering and Compression Fees

Area	$/10^3 m^3
1	28.50
2	18.00
3	14.00
4	13.50
5	15.80
6	12.50
7	14.00
8	18.30

5.2.2.9 Flowline Costs

Once a well is drilled and completed, a flowline must be installed to get the gas from the well to a gathering system. The cost of the flowline will vary with terrain but can be expressed as a function of length and pipe diameter. Flowline length was expressed as a function of the distance to a gathering system and the surface topography.

For a 100 well drilling program in each area, it was assumed that on average 100 miles of three inch diameter pipe will be required. The capital cost per inch-mile used in the analysis was shown in Table 5.10.

TABLE 5.10 Capital Cost of Flowline

Topography	$/Inch-Mile
Plains (no trees)	$20 000
Plains (wooded)	$25 000
Northern (wooded)	$30 000
Northern (muskeg)	$35 000
Foothills	$45 000

5.2.2.10 Abandonment Costs

Whether a well is a dry hole or produces for several years, at the end of its useful life, the well must be properly abandoned. Abandonment costs, as used in this study, include only the abandonment and reclamation operation. No consideration was given to the possible salvage value of any equipment. This study assumes that abandonment cost will be consistent throughout the province but that it will vary with depth according to the schedule shown in Table 5.11.

TABLE 5.11 Average Abandonment Costs for Alberta

Well Depth (m)	$/well
0 - 750	$15 000
751 - 1 800	$30 000
1 801 - 3 600	$50 000
3 601 - 6 000	$80 000

5.2.3 Economic Assumptions

5.2.3.1 Cost of Equity Capital

The Board assumed for this study that the average required return for projects in the gas industry is 15%, in nominal terms, on an after tax basis. The Board recognizes that the actual average rate of return being realized by the industry in recent years is much lower than this rate. However, the Board expects that, given the risks involved in petroleum exploration, the industry will not proceed with a project unless a minimum 15% after tax return is achievable.

5.2.3.2 Fiscal Regime

The economic analysis was consistent with the existing federal and provincial fiscal regimes. Temporary royalty incentives were not considered in the calculation and royalty payments were independent of well productivity, that is, no special royalty treatment was afforded to low productivity wells.

5.2.3.3 Inflation Rate

All costs and pricing data were input in 1991 Canadian dollars and then converted to nominal values assuming an inflation rate of 5% per annum. The 5% inflation rate does not reflect the Board's year-by-year assessment of what the inflation rate will be. Rather, it is an assumed long-range average and provides a simplistic approach to ensuring consistency with tax and royalty structures.

5.2.3.4 Price of Gas and Co-products

The gas price levels used were $1.00, $2.00, $3.00, $4.00, $5.00 and $10.00/GJ. For each of these prices, a corresponding price for propane, butanes, and pentanes plus was assumed. For example, the co-product prices corresponding to a gas price of $1.00/GJ were $40.00, $50.00, and $93.00 per cubic metre, respectively. Increasing the price of gas by a factor was assumed to result in increasing the propane, butanes, and pentanes plus prices by the same factor. However, sulphur prices have historically shown little relationship to gas prices. Sulphur prices are expected to remain soft for some time and, notwithstanding the upside potential, the Board has assumed a constant sulphur price of $70 per tonne (1991 dollars) for its analysis.

5.2.3.5 Gas Equivalent of Oil

In order to determine the portion of capital costs attributable to oil rather than gas, it was necessary to convert the oil resource to a gas equivalent volume. The Board has reviewed the various estimates of this equivalence. Although the estimates cover a fairly wide range and the actual equivalence will fluctuate as the price relationship between oil and gas changes, the Board adopted 2660 cubic metres of gas as being equivalent to one cubic metre of oil (15 Mcf/bbl). Thus, the economic return from finding 2660 cubic metres of gas was assumed to be the same as the return from finding one cubic metre of oil.

5.3 Method of Analysis

This section describes the Board's method of determining the portion of the ultimate potential gas resource which is economically recoverable at various price levels. Cash flow analysis was used to determine the required volume of gas in place per section to make exploring for and developing this gas economic. The natural gas in each section that was of sufficient volume to satisfy the economic test was aggregated to obtain an estimate of total economically recoverable natural gas.

The Board's methodology involved three major steps:

Step 1: **Gas price versus gas in place per section:** For each of the eight modified-PSAC areas of the province, tables were created which indicated, for several gas price and well depth categories, the gas in place per section required to provide a reasonable rate of return from drilling for and producing that gas. These tables were created for two scenarios; one in which no capital costs are attributable to oil exploration and development, and one in which 100% of the capital costs are attributable to oil.

Step 2: **Gas and oil in each section:** A section-by-section analysis was done for the entire province to determine each section's average anticipated gas in place and oil in place. The gas price required to render the gas resources in each section economically recoverable was obtained from the tables created in Step 1.

Step 3: **Gas price versus economically recoverable reserves:** The relationship between gas price and economically recoverable reserves in Alberta was established by totalling the gas in all sections in which the gas can be economically recovered at various gas price levels.

The following is a detailed description of the method of analysis involved in each of these three major steps.

5.3.1 Gas Price versus Gas in place

As indicated in the previous section, step one of the Board's methodology was creation of tables showing the gas in place per section required to generate an adequate rate of return (15% as discussed in Section 5.2.3.1). This was accomplished through cash flow analysis. The cash flow model calculated the after tax net cash flow by deducting from gross revenue the capital costs, operating costs, royalties, and federal and provincial taxes. Gross revenue represents the value of gas and co-product production based on a production profile and gas composition as outlined in Section 5.2.

Net cash flow was discounted to the current year. If the after tax rate of return was higher or lower than the targeted rate, a lower or a higher gas in place was selected and a new net cash flow was calculated until the desired rate of return was attained for each gas price level. The process was then repeated for each of the eight modified-PSAC areas over the range of depths of all producing formations within that area. It is important to note that most cost items and the gas and co-product prices did not change. Therefore, the target rate of return was achieved through changing the production level which, in turn, was achieved through changing the gas in place per well.

In each of the province's eight areas, a 100 well drilling program was evaluated. For each successful exploratory or development well, there are unsuccessful wells that have to be drilled to satisfy the success ratios described earlier. The drilling density can then be varied to accommodate various circumstances. The number of wells chosen to be evaluated was actually irrelevant, but the choice of 100 wells simplifies discussion of the data on a percentage basis. A cash flow analysis of a single

well cannot provide for such things as drilling success rates and differences in exploratory versus development economics.

In sections of the province where there is an accumulation of both oil and gas, it was essential to determine the portion of land, G&G, drilling and completion costs that are incurred solely due to gas-related activity. The Board determined that generally there is a linear relationship between the gas in place per section required to provide an economic return when all capital costs are attributable to gas, versus the gas in place required when all capital costs (except for flowline) are attributable to oil. Thus, it was only necessary to do the economic analysis for the two extremes of "just flowline costs" and "all capital costs" attributable to gas. As discussed in the next section, this linear relationship was used to determine the portion of capital costs attributable to gas for the specific gas versus oil ratio being considered.

There were two cases that were considered in the cash flow analysis; **full cycle** analysis which includes all costs (land, G&G, drilling and completion of both exploratory and development wells, and production and abandonment costs) and **half cycle** analysis which excludes land, G&G, and drilling and completion of exploratory wells. The underlying assumption was that in some instances these are sunk costs which do not contribute to decisions on whether to undertake development activities that could result in reserve additions.

For each of these two cases, three further scenarios were identified: Commercial, Economic and No Royalty. The Commercial scenario estimated economically recoverable gas resource in a tax and royalty burdened regime, the Economic scenario depicts a regime absent of taxes and royalties and the No Royalty scenario is one where taxes but no royalties apply. These three different scenarios provided an estimate of the fiscal impact of federal and provincial policies on the portion of Alberta's future gas potential which is economically recoverable.

The results of the economic analysis are summarized in the tables of Appendix G, which show the gas in place required to achieve an adequate rate of return at various gas price levels. Tables are included for each of the two cost allocation cases and three scenarios described above.

5.3.2 Gas and Oil in Each Section

Step two of the Board's methodology was to analyze each section in the province to determine the volume of gas in place and the oil in place which could be discovered as a result of future drilling in that section. Further, step two utilized the tables created in step one in determining the gas price required in order to achieve a reasonable economic return from drilling for and producing the gas in that section. The procedure involved in step two is discussed in the following sections.

5.3.2.1 Zones in Each Section

A computer model utilized the gas and oil play area data to identify all gas and oil zones in each section of the province. This data was used to generate Figures 3 and 4 in Appendix H which show

the number of potential gas and oil zones, respectively, in all townships in the province. The model also identified the deepest formation in each township of the province. Figure 5 in Appendix H shows this information.

5.3.2.2 Deepest Well Depth

For each township in the province, all existing wells which have penetrated the deepest formation in the township were identified. The depths of all such wells were averaged to determine the average depth of wells drilled to the deepest formation in this township. For townships where no wells had been drilled to the deepest formation, the surrounding townships were scanned to arrive at an estimate of the depth of this formation.

The economic analysis assumed that all wells drilled in a particular township will be drilled to the depth determined by this procedure. Figure 6 in Appendix H shows the average well depth required to penetrate the deepest formation in each township in Alberta.

5.3.2.3 Gas in Place per Section

In the Board's study of ultimate potential for gas in place, an estimate was made of the undiscovered gas in place in each of the 112 gas play areas identified in the study. The Board's economic analysis assumed that the undiscovered gas in place in each of the gas play areas is spread evenly throughout the undrilled sections in the play area. Figure 7 in Appendix H shows the undrilled sections of the province on an undrilled section per township basis. Given the specific potential gas zones in each section and the average gas in place for each of those zones, the total gas in place for the section was estimated.

The average gas in place per section for each township in Alberta is shown on Figure 8 in Appendix H.

5.3.2.4 Oil in Place per Section

The Board's previous study of the ultimate potential for oil, as discussed in Section 5.2.1.3, was used to estimate the future oil in place for each of the 20 oil play areas. The oil in place per section was estimated using this data and the same procedures and assumptions as were used for estimating gas in place per section.

The average oil in place per section for each township in Alberta is shown on Figure 9 in Appendix H.

5.3.2.5 Cost Allocation to Oil versus Gas

As discussed in Section 5.2.3.5, the Board has adopted a "gas equivalent of oil" factor of 2660 m^3/m^3 (15 Mcf/bbl) which was used to convert the oil in place in each section to a gas equivalent. The portion of the capital costs attributable to gas was then determined by dividing the actual gas reserves in the section by the total of the gas and gas equivalent reserves. The remaining capital costs were attributed to oil.

5.3.2.6 Gas Price Required for Adequate Rate of Return

For each section in the province (where there were no existing wells and no established reserves), the data and assumptions discussed in the preceding sections were used in the following procedure to estimate the gas price required to provide the targeted 15% after tax rate of return gas:

- determine the modified-PSAC area in which the section lies,
- determine deepest well depth required in the section,
- determine which gas zones underlie the section,
- determine the total gas in place in the section,
- determine which oil zones underlie the section,
- determine the total oil in place in the section,
- convert the total oil in place to a gas equivalent,
- determine the portion of capital cost attributable to gas,
- determine, from the appropriate gas price versus gas in place table, the gas price required to make the gas in place in this section economically recoverable where 100% of the capital costs were attributable to gas,
- repeat the above step using the tables where flowline costs were the only capital costs attributable to gas, and
- extrapolate between the two extremes of capital cost allocation, only flowline costs versus all capital costs, to determine the gas price required to make the gas in this section economically recoverable.

Each of the six economic scenarios discussed in Section 5.3.1 has its own set of gas price versus gas in place tables and each scenario was analyzed independently.

5.3.2.7 Zones Deeper Than Existing Wells

Where an existing well was drilled in a section but does not penetrate the deepest formation in the section, the analysis assumed that a new well would have to be drilled to the deepest formation. In some cases, it may be possible to deepen the existing well but industry has advised that there is seldom a significant difference between the cost of a new well versus that of deepening an existing well.

The economic analysis for such wells assumed that, although the new well was drilled from surface, only those formations below the deepest formation penetrated by the existing well would contribute production revenue for the new well. Consequently, there are a significant number of sections in the province where the economics of drilling a new well would be rather poor.

5.3.2.8 Proven Reserves In Undrilled Formations

In many sections there are formations in which the Board has already booked gas reserves even though there is no well in the section which penetrates the formation. In such cases, the analysis assumes that the new well to be drilled in this section would be able to reap the benefits of production revenue from these established reserves. While these sections benefit from improved economics as a result of the established reserves, these established reserves were not included when totalling the reserve additions attributable to this section.

5.3.3 Gas Price versus Economically Recoverable Reserves

The third and final step in the analysis was to total the reserves from each section in the province and for each of the gas price levels of interest. The ultimate potential reserves at any specified price is the total of the existing established reserves plus the total reserves in all sections where the specified price makes the reserves in the section economically recoverable.

The analysis was done for each of the eight modified-PSAC areas and was repeated for each of the six economic scenarios. Both gas in place and marketable gas volumes were calculated in all cases.

Additionally, the gas price which will, on average, make the reserves in each township economically recoverable under the Commercial Full Cycle case are shown on Figure 10 in Appendix H on a gas in place basis.

5.4 Results and Conclusions

5.4.1 Summary of Results

The Board's analysis of the economically recoverable portion of Alberta's ultimate potential for gas includes the evaluation of six economic scenarios. These evaluations were done for each of the eight modified-PSAC areas. Although the economic analysis was done on a gas in place basis, most readers are likely to be more interested in marketable gas figures. Thus, the results are presented on a gas in place and a marketable gas basis. The gas in place figures represent the initial volumes in place for all reservoirs which are could be developed at the specified price. Appropriate reservoir recovery factors and surface losses are applied to obtain the marketable gas figures.

Although the Commercial Full Cycle case represents the most restrictive scenario as it assumes a full tax and royalty burdened regime, it is the scenario which most closely represents the realities of the gas exploration and development industry. The results for this scenario are presented on a gas in place basis for the entire province in Figure 5.9 and for each of the eight areas in Figures I.1 through I.8 in Appendix I. Comparable data on a marketable gas basis is shown in Figure 5.10 and Figures J.1 through J.8 in Appendix J. The provincial data is also shown as a percentage of future gas recoverable in Figure 5.11.

The graphs show that increases in the economically recoverable reserves are most sensitive to gas price increases for prices in the range of $1.00 to $2.00/GJ. Thereafter, less reserve is added per incremental increase in price such that, beyond the $5.00/GJ level, increases in the price of gas do not significantly impact additions to economically recoverable reserves.

As shown in Figure 5.11, approximately 71% of Alberta's future gas resource can be found and developed at a gas price of $3.00/GJ. Applying the reservoir recovery and surface loss factors to these gas in place volumes implies that the ultimate potential for marketable gas is some 4800×10^9 m^3 (170 Tcf) at the $3.00/GJ price level. Obviously, at higher gas prices a larger percentage of the gas resource becomes economically recoverable. At $5.00/GJ the percentage recoverable increases to approximately 87% or 5200×10^9 m^3 (185 Tcf) of the ultimate potential for marketable gas. Economic recovery of the full ultimate potential for marketable gas of some 5600×10^9 m^3 (200 Tcf) would require prices in excess of $10.00/GJ.

The Board's forecasts suggest that gas prices will increase in the foreseeable future to levels of about $3.00/GJ in 1991 Canadian dollars. For the Commercial Full Cycle scenario at this price level, Figure 5.12 shows the future economically recoverable reserves and Figure 5.13 shows the per cent of future gas that is recoverable for each of the eight modified-PSAC areas.

By far the largest portion of the economically recoverable future gas potential lies in Area 2, some 1536×10^9 m^3 (54.5 Tcf) of gas in place, with Areas 1, 3, 4, 5 and 7 making lesser contributions but totalling some 1395×10^9 m^3 (49.5 Tcf). The percentages of future gas recoverable for these six main areas are all in excess of 65% with the exception of Area 7 where only some 40% is recoverable. The contribution from the remaining two areas, 6 and 8, is rather small, only some 49×10^9 m^3 (1.7 Tcf), at the $3.00/GJ price level. This low reserve contribution in Areas 6 and 8 stems from the combination of a small resource base, some 125×10^9 m^3 (4.4 Tcf) and 93×10^9 m^3 (3.3 Tcf) respectively, combined with very low per cent recoverable figures of 11% and 38% respectively.

The three areas showing low per cent recoverable resource, Areas 6, 7 and 8, are in the northern portion of the province and all three, as evident from Figures 3 and 4 in Appendix H, exhibit the common characteristics of few gas zones and limited oil potential. The limited number of gas zones results in a very poor average gas in place per section as can be seen on Figure 8 in Appendix H. The limited oil potential means that very little of the capital cost of recovering gas is carried by oil as is the case in the other areas. Added to these problems are the additional burdens of poor accessability, short drilling seasons, high transportation costs and, consequently, relatively high drilling costs.

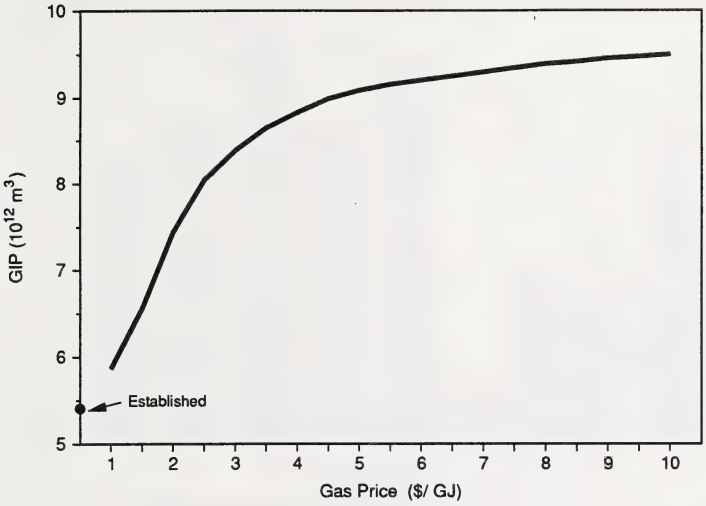


FIGURE 5.9 GAS PRICE vs ULTIMATE GAS IN PLACE - ALBERTA. Commercial Full Cycle Scenario

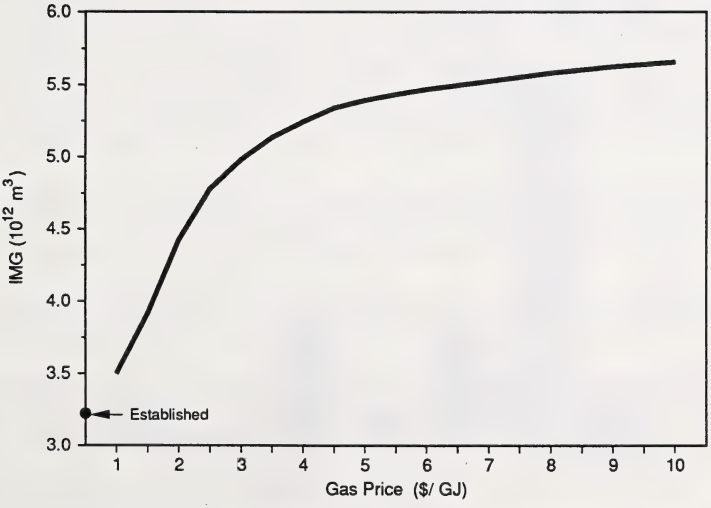


FIGURE 5.10 GAS PRICE vs ULTIMATE POTENTIAL - ALBERTA Commercial Full Cycle Scenario

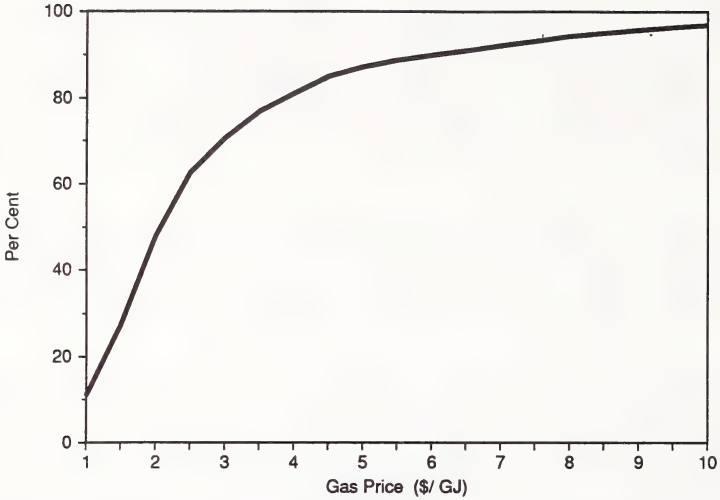


FIGURE 5.11 GAS PRICE vs PER CENT OF FUTURE GAS RECOVERABLE
Commercial Full Cycle Scenario

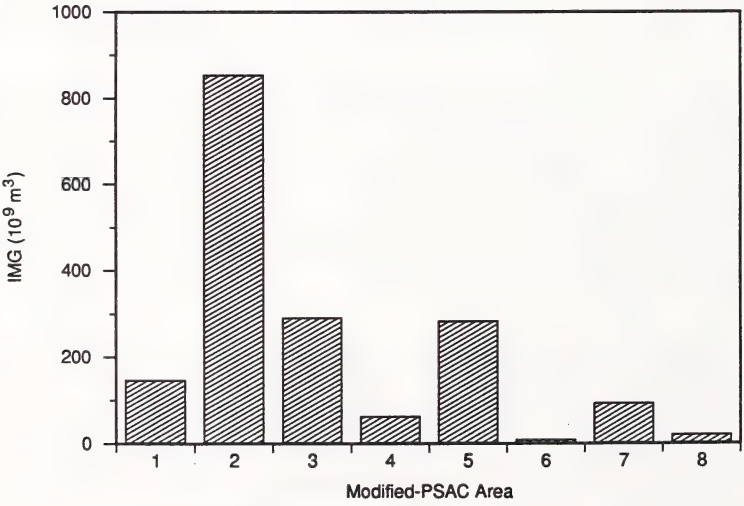


FIGURE 5.12 ECONOMICALLY RECOVERABLE FUTURE GAS AT $3.00/GJ

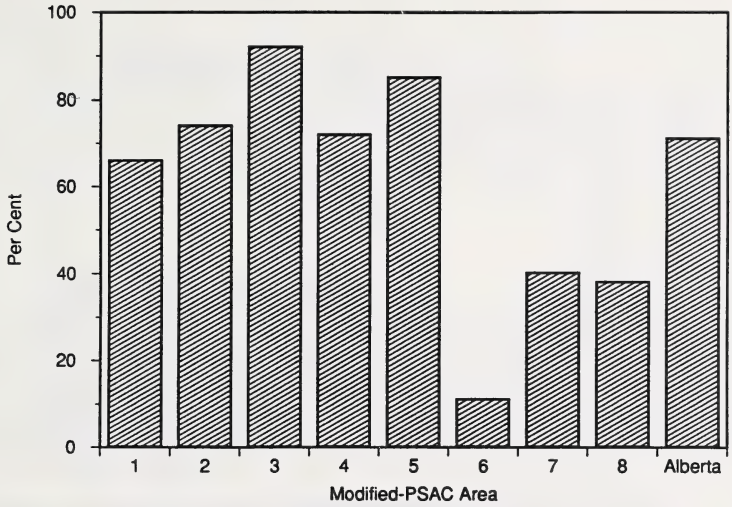


FIGURE 5.13 PER CENT OF FUTURE GAS RECOVERABLE AT $3.00/GJ

Notwithstanding this pessimistic outlook for modified-PSAC Areas 6, 7 and 8, there has been a nominal amount of drilling in these areas in recent years which is continuing at the current time. This illustrates the limitations of our assumption that the reserve potential is spread evenly throughout the entire play area. In actual practice, there are always "bright spots" in each play area where the economics of gas recovery are much better than the area average. A prime example of this exists in the Peace River Arch region of Area 7 where the number of gas zones, gas in place per section and general drilling conditions are much better than throughout the remainder of the area.

Area 6 includes no conventional crude oil reserve potential. However, the area may hold somewhat more promise than suggested by the analysis as a result of some gas development which may take place in conjunction with the significant bitumen related activity anticipated for this area.

The prospects for Area 8 hinge on anticipated activity related to oil exploration and development. However, in much of the area there is no oil and the outlook for such regions is rather bleak.

The ultimate gas in place recoverable at various gas prices is shown for all six economic scenarios in Figure 5.14. Similar results are shown on a marketable gas basis in Figure 5.15. As expected, at any given price, the Economic Half Cycle scenario (royalty and tax free regime using half cycle economics) yields the highest percentage of economically recoverable gas resource (96% at $3.00/GJ) while the Commercial Full Cycle yields the most pessimistic scenario (70% at $3.00/GJ). For the Full Cycle cases, eliminating taxes and royalties results in an increase in the percentage of recoverable

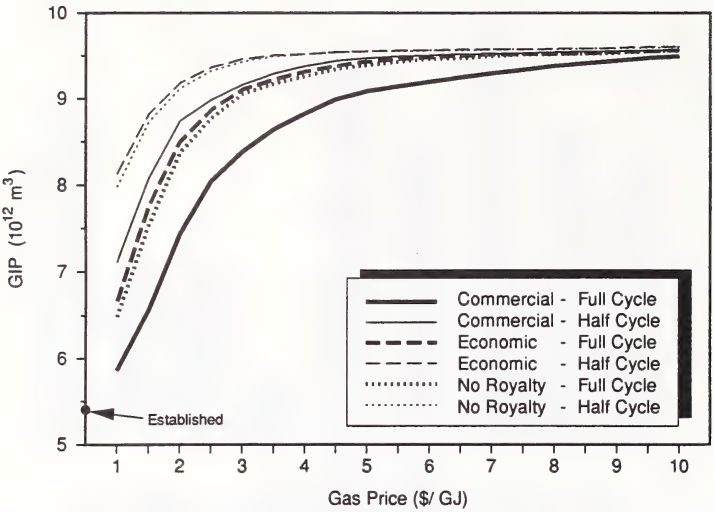


FIGURE 5.14 GAS PRICE vs ULTIMATE GAS IN PLACE

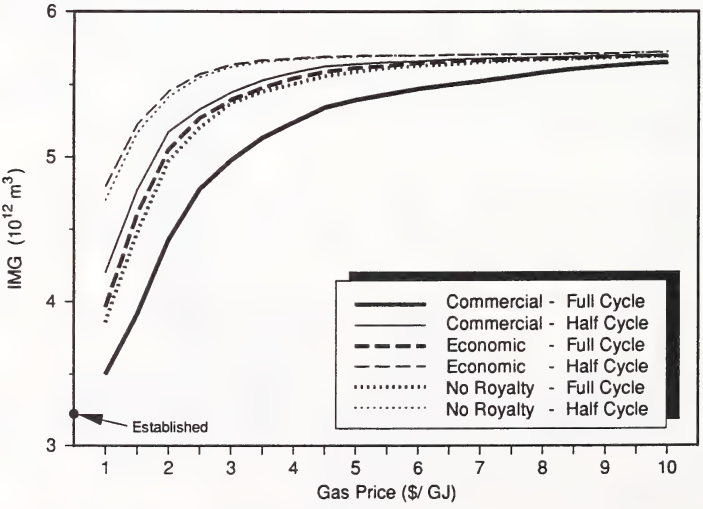


FIGURE 5.15 GAS PRICE vs ULTIMATE POTENTIAL

reserves to 88%. Eliminating royalties alone would have only slightly less impact, improving recovery to 86%.

Detailed tabulations of the gas in place figures for each area and economic scenario are shown in Appendix I for the $1.00, $3.00, $5.00 and $10.00/GJ price levels. Similar tabulations on a marketable gas basis are shown in Appendix J. Additionally, the gas price which will, on average, make the reserves in each township economically recoverable under the Commercial Full Cycle scenario are shown on Figure 10 in Appendix H.

5.4.2 Conclusions

While the results of the Board's study are not precise, they do represent reasonable estimates of Alberta's economically recoverable gas reserves at various price levels. Further, they provide a basis upon which to estimate the impact of cost variations as a result of technological change, government incentive programs, or a wide variety of cost cutting measures. Conversion of the recoverable reserve estimates to annual deliverability forecasts, as is done in Chapter 7 of this report, may provide insight for consumers and producers alike.

The results of the analysis suggest that there are significant reserves of economically recoverable gas in Alberta even at the relatively low prices currently being experienced.

5.5 Critique of the Methodology

This section is intended to provide a summary of the strong points of the Board's economic analysis as well as to point out the pitfalls of which the reader should be cognisant.

5.5.1 Stacked Zones

The Board considers its treatment of the stacked zones problem to be one of the strong points of its methodology. Most analyses have trouble dealing with the interaction of various play areas but the section-by-section analysis accounts for multiple zones in a single section or area.

5.5.2 Costs Attributable to Oil

The treatment of capital costs attributable to oil provides for the reality that exploration companies do not search specifically for oil versus gas or vice versa. While there may be a greater expectation of finding one versus the other and the rewards are generally higher in the case of oil, the fact remains that, in sufficient quantities, either resource can generate a good return on investment.

5.5.3 Resource Spread Throughout Play Area

Probably the most problematic of the assumptions in the methodology is the assumption that the future resource in each play area is spread evenly throughout all undrilled sections of the play area. This assumption results in a significant dilution of the gas anticipated to be found in the "bright spots" of the play area and thus produces a pessimistic view of the economics of gas recovery in the area. This is less evident in areas of the province where there are several zones involved but becomes significant in the northern regions of the province where few zones are present. The problem is discussed further under the summary of results in Section 5.4.

5.5.4 Seismic Reduction of Drilling Density

Related to the problem of assuming the resource is spread evenly throughout the play area is the error introduced when seismic is used to target only those sections where reserves exist, thus reducing the number of wells required to discover the reserve. This was compensated for in modified-PSAC Area 1 by assuming that there is only one well drilled per two sections but the problem likely exists in some other areas of the province.

5.5.5 Relatively High Costs Assumed

For the most part, the Board has been rather conservative in its estimates for the various cost data. Individual companies may be able to drill at lower costs than assumed here, particularly where experience, accessibility, existing facilities or other circumstances combine to provide cost cutting.

5.5.6 Drilling Density Greater Than One Well per Section

In some areas of the province the drainage characteristics of the reservoirs or the problem of very small pools may result in a requirement to drill more than one well per section. In such cases, the Board's methodology produces a somewhat optimistic result. However, this problem is not expected to be significant.

5.5.7 No Regard for Bitumen Drilling

In some areas, particularly modified-PSAC Area 6, some gas development may take place as a result of bitumen related activity. Bitumen is not expected to provide a great deal of benefit to gas development but the method yields a somewhat pessimistic result in these cases.

5.5.8 Co-product Pricing

Holding the sulphur price constant in nominal terms certainly has a negative effect on the economic viability of exploration and development activities in modified-PSAC areas that have significant sulphur production potential, such as Areas 1 and 2. If sulphur prices were to rebound to the higher levels experienced in the recent past, this assumption would produce a pessimistic result.

5.5.9 Full versus Half Cycle Economics

Some portion of future reserve additions will unquestionably be as a result of development related drilling activities for which land, G&G and exploratory drilling costs are sunk costs and would not, therefore, be included in any profitability analysis. Thus, the most realistic case will be somewhere between the Full and Half Cycle cases. Unfortunately, no mechanism is readily available for determining precisely where reality lies between these two cases.

5.5.10 Low Productivity Wells

As mentioned in Section 5.2.3.2, our analysis does not provide for special royalty treatment of low productivity wells. While the reserve contribution from such wells is probably low this treatment of such wells will produce a somewhat pessimistic result.

5.5.11 Overall Reliability of Results

While there are several situations which tend to skew the results in one direction or the other, the Board feels its methodology produces a reasonable estimate of the economically recoverable reserves at various price levels, particularly on a provincial basis. The results are somewhat less reliable when looking at specific regions of the province as is discussed in more detail in Section 5.4.1.

6 RESERVES GROWTH FORECAST

Annual reserves growth depends on the number of sections drilled during the year and the average reserves added per section. The Board's forecast of sections drilled is prepared on a judgemental basis having regard for historical drilling patterns and anticipated future developments in the gas industry. A statistical analysis is used in preparing a forecast of reserves added per section.

The forecasts in Chapter 7 are for a 15-year period. Forecasts which extend beyond this point are generally not very useful and certainly not very precise. However, the drilling and reserves growth forecasts are extended 25 years into the future in order to present the very long term perspective as the ultimate potential for conventional gas is approached.

6.1 Method of Analysis

The Board has analyzed historical reserves growth information in combination with the data compiled in its economic analysis to arrive at a forecast of the average amount of gas which will be added per drilled section. This forecast of gas additions per section was then combined with a forecast of drilling activity to arrive at a forecast of annual reserve additions. The forecast of reserve additions was input to the Board's deliverability model to determine the gas supply and its relationship to demand for Alberta gas.

If the gas supply versus demand did not appear reasonable, the drilling activity forecast was adjusted and the forecasting procedure was repeated until both the drilling forecast and supply versus demand forecasts appeared consistent. While the entire process is judgemental, the method ensures that the reserves growth forecast is based on an attainable level of drilling activity. The following sections include discussions of reserve additions per section, drilling, and reserve additions forecasts. Supply and demand are discussed in Chapter 7.

6.2 Historical Reserve Additions

The ERCB, CPA and other organizations publish annual updates of gas reserve additions in Alberta. Studies requiring historical reserves additions data generally rely on these published estimates. Unfortunately, revisions to individual reserve estimates and changes in methodology result in anomalies in the data. These anomalies create problems in studies which rely on a correlation of reserves growth and drilling activity.

The Board has looked at several techniques which could be used in analyzing historical reserves growth so as to avoid these anomalies. A discussion of each of these techniques and the results of the analyses are presented in Appendix K. The technique adopted for use in this report is one in which reserves in each pool, based on the most recent reserves estimate, are divided among all sections in the pool. The year of discovery for the reserves in each drilled section is taken as the finished drilling date of the well. Undrilled sections are dated based on the dates for the drilled sections. The historical reserves growth as determined by this technique is presented in Figure 6.1.

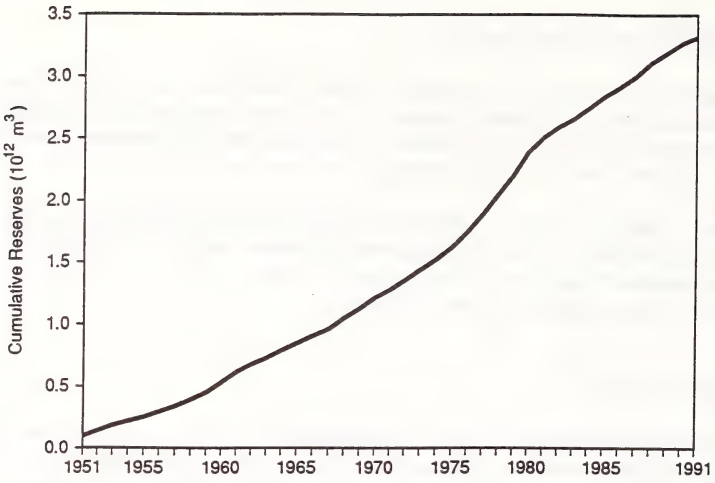


FIGURE 6.1 HISTORICAL RESERVES GROWTH

6.3 Reserve Additions per Section

In its economic analysis study discussed in Chapter 5, the Board estimated, for every section in the province, the future gas reserves to be discovered and the gas price at which such reserves would be economically recoverable. This section data was sorted by gas price. The reserves per section from this sorted listing provided an indication of the trends in future reserves per section. This process assumes that the sections yielding the best economic return will be drilled first.

The price sorted data was combined with the historical reserves growth data and plotted on an IMG per section versus cumulative sections drilled basis. The best fit line for all data excluding the first 20 000 sections yields a fairly good correlation and it was used as a reasonable approximation of the IMG per section for future drilling in Alberta. Figure 6.2 shows the plot of the historical and forecast IMG per section data as well as the best fit line.

6.4 Drilling Activity Forecast

Drilling activity depends upon the number of drilling opportunities available, the availability of resources to actually drill the wells, the opportunity to produce and sell any oil or gas discovered, and the profitability and risk of the oil and gas industry versus other investment opportunities. Behind each of these fundamental parameters lies a long list of variables which influence the basic parameter. Product prices, tax and royalty structures, government policies, the economic viability of other industries, interest rates, product demand, productive capacity, land acquisition opportunities, geological potential, and rig availability are but a few examples of these variables.

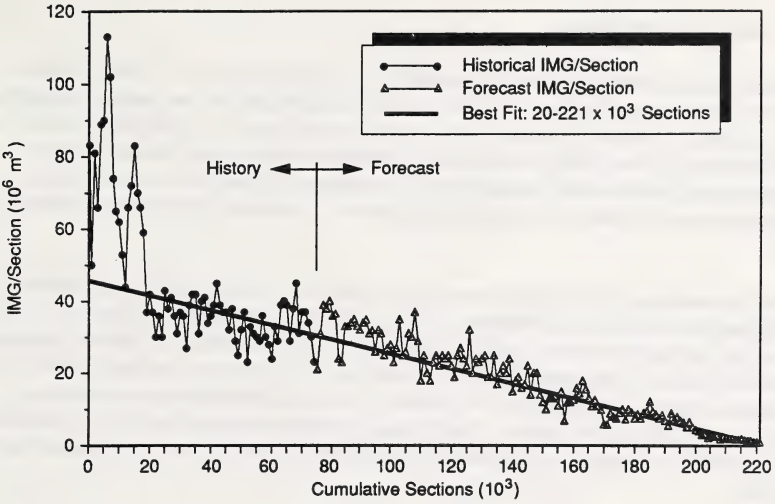


FIGURE 6.2 RESERVES GROWTH vs CUMULATIVE SECTIONS

The Board has looked with considerable interest at Sproule's treatment of this subject as contained in the TCPL submission. Sproule uses a multiple regression analysis of several variables in attempting to forecast drilling activity. The technique is particularly interesting with respect to scenario analysis. However, the Board has not undertaken the onerous task of creating its own model to predict drilling activity. In light of the large number of variables to be considered in a multiple regression equation and the fact that a forecast must be made for each of these variables, the Board chose to use a more simplistic, judgemental approach in preparing its drilling forecast.

Very low levels of drilling activity are expected in the current and following year. Activity is then expected to grow very rapidly such that it doubles by the turn of the century. The Board's analyses show that, given market demand increases, significant additional drilling activity will be required in the mid to late 1990s, particularly to meet the need for increased peak day deliverability. This high level of drilling activity must be sustained for several years as reserve replacement becomes increasingly important. In the longer term, 20 to 25 years, activity is likely to decline as gas exploration begins to encounter geological limitations.

To sustain the reserves growth, drilling activity is expected to increase from the current low of some 3500 wells per year to a high of some 6000 wells by the end of the decade. These estimates are of total wells drilled for oil or gas in Alberta including exploration, development, successful, and unsuccessful wells. Based on historical wells drilled versus sections drilled ratios, this drilling activity translates to a range of about 1500 to 3200 sections drilled per year.

6.5 Reserves Growth Forecast

The Board's method of forecasting reserves growth is an iterative procedure. An initial forecast of reserves growth is generated by combining the forecast of reserve additions per section described in Section 6.3 with the forecast of sections drilled as discussed in Section 6.4. This initial forecast is input to the Board's deliverability model to ensure consistency with the supply/demand balance. As deemed necessary, the forecast of sections drilled is adjusted and the procedure repeated. This judgemental approach is used to ensure that drilling activity is consistent with the supply/demand balance.

The Board's reserves growth forecast is presented in Figure 6.3. Reserves growth is expected to increase from the current level of 50 to 60 $\times$ 10^9 m^3 (1.8 to 2.1 Tcf) per year to almost 90 $\times$ 10^9 m^3 (3.2 Tcf) per year early in the next century. A gradual decline is expected in the ensuing decade even though drilling activity is expected to remain at a high level. As drilling activity begins to drop off in the long term, reserve additions decline quite rapidly. Alberta's ultimate potential would not be reached until well into the next century. The 25-year projections shown in Figure 6.3 are provided largely for illustrative purposes as circumstances surrounding the industry are very uncertain that far in the future.

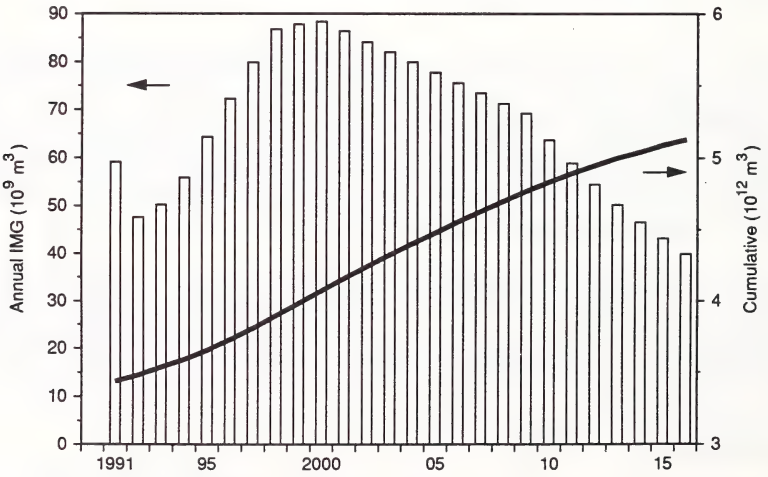


FIGURE 6.3 RESERVES GROWTH FORECAST
m^3 at 37.4 MJ/m^3

7 SUPPLY AND DEMAND

7.1 Gas Demand

The Board reviews the demand for Alberta gas on a periodic basis. Details of the most recent review are contained in ERCB Report 91-A[1]. The focus of these reviews is on intra-Alberta gas use and a detailed analysis is undertaken of the many factors which influence gas consumption in the province. Population growth, economic activity and industrial growth are but a few examples of these factors. Forecasting of demand for Alberta gas in markets outside the province is done on a less rigorous basis. For Canadian ex-Alberta markets, historical demand growth and the published estimates of other organizations are used in developing the forecasts. Export markets are forecast on the basis of anticipated pipeline capacity to serve such markets and the historical trends in demand growth in those markets. The published estimates of other organizations are also reviewed in forecasting the export market.

The Board's demand forecasts are shown for Alberta, Canadian ex-Alberta, and export markets in Figure 7.1 and in Table L.1 in Appendix L.

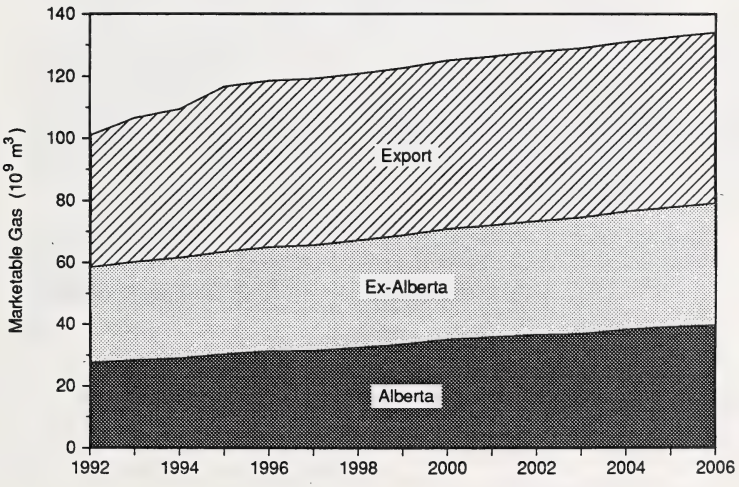


FIGURE 7.1 FORECAST OF DEMAND FOR ALBERTA GAS

---

1 Energy Resources Conservation Board, 1991. **Energy Requirements in Alberta, 1991-2005.** ERCB Report 91-A. Calgary, Alberta.

7.2 Gas Supply

The Board uses a commercially available deliverability model and its own database to assess the province's ability to meet the demand for Alberta gas. The total supply capacity is matched to the demand on an annual basis and the expected production is taken as the lesser of the capacity and the demand. The model forecasts deliverability for both established and future reserves. The forecast of supply from established reserves is divided into several categories: major pools, cycling pools, southeastern Alberta shallow gas pools, solution pools, injection pools, deferred and beyond economic reach.

The forecast of expected gas production from each of these categories and from future reserve additions is shown in Figure 7.2 and Table L.1 in Appendix L. The details of the forecasts are discussed in the following sections.

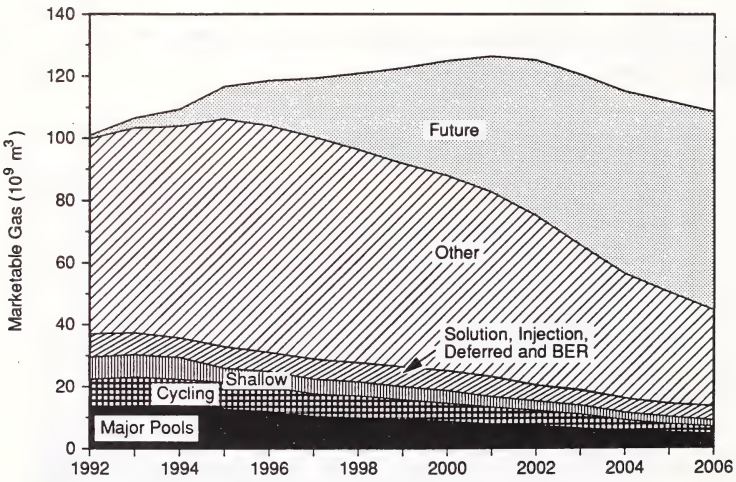


FIGURE 7.2 GAS SUPPLY FORECAST

7.2.1 Supply from Established Reserves

The Board's forecast of production from established reserves incorporates measured or estimated reservoir parameters, existing wells and production facilities, and estimated contract rates of take. Drilling of development wells and installation of additional production facilities are also assumed in order to meet contract commitments as long as possible.

The contract rate is taken as one unit of production per day for each 7300 units of initial reserves. This 1/7300 rate of take is based on historical contracting practices and equates to a contract life of 20 years.

Some 75% of Alberta's production from established reserves is from pools which can be considered to be tank type reservoirs in which gas expansion is the only drive mechanism. These pools are referred to as depletion pools and the Board's deliverability model generates forecasts for these pools based on reservoir and facility input data. Although some of these reservoirs may have secondary drive mechanisms, the error is not expected to be significant in relation to other simplifying assumptions used in the forecasting procedure.

The remaining non-depletion type pools include cycling pools, Southeastern Alberta shallow gas pools, solution gas pools, and injection pools. Manual forecasts are developed for each of these categories of pools and these forecasts are input as fixed forecasts which the model simply incorporates in the total forecast. Two other categories of reserves, beyond economic reach and deferred, are considered depletion type reservoirs but require special consideration to determine production start dates.

The Board has studied the deliverability of the pools in each of these categories and has also done a detailed review of the 21 major pools in the province. Each category is discussed in the following sections.

7.2.1.1 Major Pool Study

A detailed study was carried out on the major gas pools in Alberta, those with remaining marketable gas reserves of greater than 5×10^9 m^3. These 21 pools currently account for about 13% of total gas production in Alberta.

Each of the major pools was reviewed individually with a view to future gas production and deliverability. The study considered current contract rates of take, development drilling, production history, company forecasts, and reservoir characteristics for each pool.

Individual pool forecasts for the major gas pools in the province are shown in Table L.2 in Appendix L. The first 10 years and the 15th year of these major pool forecasts are included. Gas production from the major pools is expected to increase somewhat through the early 1990's to 14×10^9 m^3 per year, largely due to the impact of the Caroline Beaverhill Lake A pool. Production from these pools declines throughout the remainder of the forecast and by the end of the forecast period, amounts to only some 5×10^9 m^3 per year.

7.2.1.2 Cycling Pools

The Board's projections of expected production from cycling pools is largely based on operator intentions as submitted in annual progress reports and on Board approved production rates.

As shown in Table L.1, gas production from cycling pools is expected to stay fairly constant at 9.0×10^9 m^3 per year during the early 1990's, but decline thereafter to a level of some 2.3×10^9 m^3 in 2006.

Production from cycling pools accounts for roughly 9% of total gas production at the start of the forecast. Production is, however, expected to decrease gradually to 2% by the end of the forecast period. Individual cycling pool forecasts are shown in Table L.3 in Appendix L.

7.2.1.3 Southeastern Alberta Shallow Gas Pools

The Board's forecast of gas production from Southeastern Alberta shallow gas reserves is shown in Table L.1. About 7.5×10^9 m^3 per year of gas production is expected from these pools in the early 1990s. This rate is expected to decline throughout the remainder of the forecast to some 3.2×10^9 m^3 per year by the end of the forecast period.

The Board's production forecasts for shallow gas pools are based on a detailed analysis carried out in 1989. This analysis considered current contract rates of take, infill drilling, production history, and reservoir characteristics for each field and pool.

Production from shallow gas reserves accounts for 7% of gas production at the start of the forecast but declines to 3% by the end of the forecast period. Shallow gas production forecasts are shown on a field basis in Table L.4 in Appendix L.

7.2.1.4 Solution Gas Pools

The Board reviewed about 40 of the largest solution gas pools. Gas production forecasts were generated using an estimate of the future oil to gas ratio and the Board's most recent forecast of oil production for the pool. The forecasts for these larger solution pools are shown in Table L.5 in Appendix L.

Total gas production from solution gas pools is expected to decline from the current level of 7.0×10^9 m^3 per year to a level of 1.3×10^9 m^3 per year by the year 2006. About 7% of gas production from established reserves is from solution gas. The Board expects this percentage to decline throughout the forecast period to roughly 1% by the year 2006.

7.2.1.5 Injection Pools

Gas is injected into the gas caps of several oil pools in the province in order to maintain reservoir pressure and, thus, provide increased oil recovery. Production from these pools must be forecast manually due to their special nature. These pools contribute only about 0.7×10^9 m^3 per year, less than one per cent, at the present time and their contribution is expected to decline to less than

0.2×10^9 m^3 per year by the end of the 15-year forecast period. Pool-by-pool forecasts for injection pools are shown in Table L.6 in Appendix L.

7.2.1.6 Beyond Economic Reach Pools

Pools which contain established reserves but which cannot be produced given current economic conditions and proximity to existing facilities are called beyond economic reach pools. Production start dates for these pools are estimated based on reserves size. Thus many of the larger pools will start to produce during the forecast period but the smaller pools will not come on stream for many years into the future.

Reserves currently considered beyond economic reach are expected to come on stream in the mid 1990s. Production is expected to build to a high of some 2.4×10^9 m^3 per year early in the next century. During the forecast period, pools currently considered beyond economic reach are expected to contribute less than 3% of total production.

7.2.1.7 Deferred Pools

Deferred gas is principally gas associated with oil reservoirs. This gas provides the drive mechanism for oil production and therefore cannot be produced until the oil pool is depleted. An estimate of the on production date for each pool is input to the deliverability model which treats them as normal depletion pools after the specified date.

Production from deferred reserves only becomes significant toward the end of the forecast period. In the final year of the forecast, production reaches a high of 1.3×10^9 m^3 per year and amounts to some 1% of total Alberta production.

7.2.2 Supply from Future Reserves

The Board's deliverability model uses the forecast of reserves growth as discussed in Chapter 6. This forecast is used in conjunction with a connection rate schedule and a production profile to generate a forecast of supply from future gas reserves.

The time required to connect a particular reserve after it has been discovered can vary a great deal. A well drilled in close proximity to an existing production facility may be placed on production in a matter of days after the finished drilling date of the well if the company has a gas contract. Conversely, a well drilled in an undeveloped area may not be connected for several years. The Board has assumed that 25% of the reserves discovered in a particular year are connected in each of the four years after discovery. While this is an over simplification, the Board believes it is within the accuracy limitations of the other estimates that make up a forecast of future gas production.

The contract rate of take used for future reserves is 1/5000. This rate is faster than for established reserves and reflects industry's move in recent years to shorter term contracts. The reserve is assumed to produce at this rate until some 40% of the reserve is depleted. This portion of the production profile is referred to as the flat life of the profile. Thereafter, the production is forecast to decline exponentially until the reserve is depleted.

7.2.3 Gas Supply versus Demand

The Board's forecasts of demand, expected production and supply capability are shown in Figure 7.3 and in Table L.1 in Appendix L. The figure suggests that supply will be able to meet demand until 2001. After that time, gas supplies from other sources, unconventional gas or frontier gas, would be required to meet the demand for Alberta gas.

Gas production from established reserves will meet over 80% of the anticipated demand for gas during the next six years. The percentage of gas production from established reserves declines over the remainder of the forecast period and by the year 2006 amounts to less than 45% of total gas production. Current drilling activity is at a very low level and it will take some time to regain the higher levels required to ensure adequate reserve replacement.

The Board's forecast of demand assumes fairly vigorous growth and the supply forecast assumes rates of take and drilling activities which are rather conservative. The supply shortages in the first decade or so of the next century are not due to a lack of reserves available for discovery. Thus, shortages this early in the forecast period are avoidable. However, the forecasts do suggest that significant industry activity will be required in the coming years if the anticipated shortages are to be avoided.

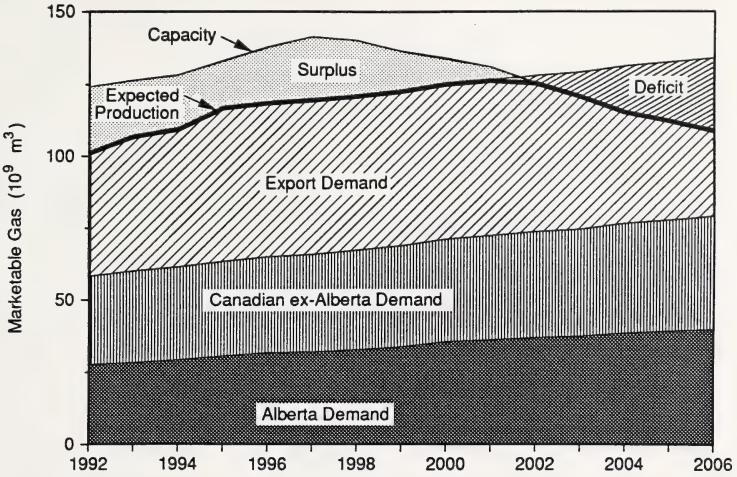


FIGURE 7.3 SUPPLY AND DEMAND FOR ALBERTA GAS

8 UNCONVENTIONAL GAS

8.1 Introduction

In addition to conventional gas, Alberta also has two large unconventional gas resources; gas in ultra low permeability reservoirs (tight gas) and gas in coal seams (coalbed methane). Section 1.1 includes a discussion of the several factors which are considered in defining the difference between conventional and unconventional resources. In general terms, there is less information and experience available on unconventional gas, and improved technology and economics are required to develop the resource.

Investigations into tight gas and coalbed methane began in Alberta in the late 1970s when gas prices were high and there were expectations of significant increases in market demand. In the early to mid 1980s, as gas prices fell and increases in demand failed to materialize, interest in unconventional gas began to wane. Today's gas demand and prices still do not justify high interest in unconventional gas. However, given the extremely large estimates of the unconventional resource base, there is little doubt that this resource will command a great deal of interest in the future. Unfortunately, the available estimates of the unconventional resource base are extrapolations of limited reservoir data, with considerable range and uncertainty. The quality of the estimates has not changed significantly since the Board's last major review of ultimate gas potential in 1979.

In the past, optimistic estimates for unconventional gas development have relied upon assumed improvements in technology. Over the last decade, it has become apparent that a more appropriate approach may be to focus on investigating what gas price is necessary to make unconventional gas production economic in the absence of technological advancements. Unfortunately, economic analyses of Alberta's unconventional gas resources is highly speculative because of the limited data available on such resources in Alberta.

8.2 Tight Gas

Most of Alberta's tight gas is found in a thick section (4600 m) of Mesozoic clastic sediments, which is located in the deepest part of the Western Canadian Sedimentary Basin, or Deep Basin as it is commonly known. The Alberta portion of the Deep Basin covers about 16 000 square kilometres and is bounded by the foothills thrust belt to the southwest and by an updip water seal to the northeast. About 2100 m of the Mesozoic section is thought to be completely gas saturated, based on geophysical data and laboratory testing. The section contains sandstones, siltstones, shales, coals, and some conglomerates. While the conglomerates display conventional gas reservoir characteristics and have been commercially produced, the sandstones, although gas saturated, typically have in-situ permeabilities in the microdarcy range. It is the ultra low permeability of the sandstones in which the gas is trapped that gives rise to the term tight gas.

In order to achieve appreciable gas production rates from such low permeability rock, it is necessary to significantly increase the surface area of the reservoir in contact with the wellbore. A number of

approaches have been attempted in the US, but massive hydraulic fracturing (a process whereby the reservoir is fractured around the wellbore using large volumes of fluids and proppant pumped down the wellbore under high pressure) is the most promising. A successful massive hydraulic fracture treatment creates a fracture that extends several hundred metres out from the well, but is confined vertically to the formation of interest, with the fracture being held open by the proppant, usually sand. The additional cost of such treatments may more than double the cost of a well. It should be noted that a continuum of gas reservoir quality from conventional to tight exists throughout the province. Within this continuum are low quality, sub-economic conventional reservoirs which are not considered to be tight reservoirs in the context of this study. These sub-economic conventional reservoirs are likely to be developed before the even lower quality unconventional tight gas reservoirs.

Also, all gas production coming from designated tight gas areas in the US is referred to as tight gas. This practice results in gas production from sweet spots and stringers of higher permeability reservoir being included in US tight gas production totals. Therefore, it is also important not to confuse what may be referred to as tight gas in the US with the true ultra low permeability gas resources being described in this study.

The estimates of Alberta's tight gas in place supplied to the Board during this study range from 5×10^{12} m^3 (175 Tcf) to 42×10^{12} m^3 (1500 Tcf) and are based on data sets containing geological information from between 40 and 400 wells. Considering the large area over which this data must be applied, the large range of gas in place estimates is indicative of the early stage of reservoir characterization for tight gas in Alberta. The Board accepts gas in place estimates toward the lower end of the range, but believes that gas prices into the foreseeable future will remain too low to encourage development of this gas resource.

A cursory analysis of the economics of tight gas production indicate that very large increases in gas prices are necessary to make this resource economic to develop. The high cost of massive hydraulic fracturing, and the low gas flow rates experienced from Alberta tests on such reservoirs to date would require gas prices in the order of $10.00/GJ to become attractive for commercial development. The accuracy of this high gas price is certainly arguable, however, it does serve to illustrate the gap between current economic conditions and those required for development interest in this resource to become significant.

8.3 Coalbed Methane

Coal bearing formations underlie more than 45% of Alberta, and are associated with Upper Jurassic, Cretaceous and Lower Tertiary strata. Much of this coal may be of suitable thermal maturity, or rank, to hold potential for coalbed methane development. The rank of the coals generally increases with increasing depth of burial and to the west toward the mountains. Coal gas contents usually increase with rank, making the higher rank coals more attractive as coalbed methane reservoirs.

Unlike conventional gas reservoirs, coalbed methane is sorbed[1] by the coal rather than just being held as free gas in the matrix porosity. The term sorbed is used because it remains unproven whether the methane is actually adsorbed onto the coal surfaces or absorbed into the coal molecular structure, although adsorption appears to be the most popular theory. Coal seams are generally water saturated, making it necessary to remove the water from the coal fracture or cleat system before gas will start to desorb from and diffuse through the coal, and flow through the fractures to the wellbore. Therefore, a period of de-watering lasting from days to months is usually necessary in advance of gas production. Also, a natural or induced fracture system is important to allow de-pressuring of the coal seam, and provide a flow channel to the wellbore.

Coalbed methane, as its name implies, typically consists of 95% methane, with the remaining 5% consisting of ethane, carbon dioxide, nitrogen, helium, and hydrogen. Coalbed methane has been found to contain, at the most, only trace amounts of hydrogen sulphide, even from high sulphur content coals. Therefore, little processing of coalbed methane usually is required to get it to pipeline standards.

The amount and quality of water produced with coalbed methane may vary with factors such as the depositional and burial history of the coal; the hydrogeologic setting of the specific coal bearing basin; and the development and water saturation of the coal cleat system. The limited Alberta specific data available to date suggests that water produced from Alberta's coalbed methane reservoirs may be of comparable quality to that of produced water from conventional oil and gas reservoirs in the province. There is reason to expect that water produced with coalbed methane may be of even superior quality by analogy to water produced in US coalbed methane operations. The produced water will require disposal in an environmentally acceptable manner, which essentially means subsurface deep well disposal in Alberta, and this will add to operating costs.

Coalbed methane presents the best current potential for unconventional gas development in Alberta by virtue of the province's extensive coal deposits, which translates into probable low finding costs, and the applicability of conventional technology to coalbed methane operations. The coals of the foothills and mountains may hold higher concentrations of gas than coals in the plains region, but environmental concerns and much higher development costs may make them less favourable for coalbed methane production. Areas of the province with extensive conventional oil and gas wells that could be re-completed in coal seams as the conventional zones deplete could offer significant potential for coalbed methane development, especially if existing gas infrastructure exists in the area. However, re-completion attempts may be hampered by damaged coal zones resulting from the original conventional drilling of these wells.

For the subject study, five estimates of Alberta's potential coalbed methane volume in place were available from submissions received in response to ERCB General Bulletin GB 90-11, discussions with individual companies, and the literature. The estimates ranged from about 7×10^{12} m^3 (250 Tcf) to 73×10^{12} m^3 (2600 Tcf), with most being in the lower end of the range. Given the extremely limited

---

1 Raoul Choate, John P. McCord and Craig T. Rightmire, 1986. Assessment of Natural Gas from Coalbeds by Geological Characterization and Production Evaluation, **AAPG studies in Geology #21,** American Association of Petroleum Geologists, Tulsa Oklahoma, pp. 223-245.

amount of data available on key coalbed methane resource parameters for Alberta, the high end estimates are believed to be too speculative and too far into the future even to be considered at present. Also, in the US, where current tax credit, gas supply, and market proximity considerations are more favourable for coalbed methane development than in Alberta, the total coalbed methane resource in place generally is estimated at about 11.3×10^{12} m^3 (400 Tcf). Therefore, the lower end estimates of 7×10^{12} m^3 (250 Tcf) to 11×10^{12} m^3 (390 Tcf) which are still very significant volumes, are believed to be the more reasonable estimates of Alberta's coalbed methane volume in place at present.

The Board conducted cursory economic analyses of coalbed methane using data gleaned from US coalbed methane operations and the limited data available for Alberta. Scenarios for both the foothills and plains areas of the province were developed assuming that medium to low volatile bituminous coal would be targeted, and that gas production rates would peak at 21×10^3 m^3/day (750 mcf/day) within 3 years. The use of conventional drilling rigs, and the need to hydraulically fracture the coal seams were assumed. Runs were made for the cases of exploration and development wells, as well as for recompletions of depleted conventional wells. A single well was assumed in all cases which, therefore, assumes a 100% drilling success rate.

The analyses assumed a well depth of 1200 metres in the plains and only 800 metres in the foothills but drilling, infrastructure, and other costs were much higher in the foothills. Assuming recompletion of depleted conventional gas or oil wells and the use of existing infrastructure significantly improves the economic viability of coalbed methane development. Opportunities for the use of such wells and infrastructure are extremely limited in the foothills, but common throughout the plains areas. The economic analyses indicated that gas prices as low as $2.00/GJ may be sufficient to yield a 15% after tax rate of return on certain coalbed methane developments in the plains areas.

The Board has not attempted to quantify the fraction of the coalbed methane resource which may be economic to develop at $2.00/GJ. However, until such gas prices are realized, the incentive to pursue the resource in a significant manner will not exist, and development is likely to be very limited.

8.4 Reserves Potential

Given the uncertainty of in-place volumes and the uncertainty of successful recovery, it would be premature and inappropriate to predict what recoverable reserves may be for unconventional gas. Given the magnitude of the in-place volumes, even recovery levels as low as 10% would result in significant reserves additions. At this time, the Board believes that quantifying estimates of recoverable reserves would have to allow for an excessively broad range of uncertainty. Therefore, the Board will continue to exclude unconventional gas from it's quantitative estimates of ultimate potential.

However, in a qualitative sense, coalbed methane reserves potential in particular is believed to be significant, and represents a likely future gas supply source. Provided that established drilling and completion technologies can be applied to Alberta's coalbed methane reservoirs, it may be economic

to begin developing these reservoirs at lower gas prices than would be necessary for other unconventional gas resources.

Additional reservoir characterization and investigations into producibility are required to further define the reserve potential of Alberta's unconventional gas resources. Although unconventional gas is unlikely to be needed in the near term as a source of supply, ongoing efforts are warranted to better quantify the resource. Such efforts should include more detailed reservoir delineation using existing and additional well information, plus some representative measure of actual gas production. Commercial development is not necessarily required to provide the information. But, some measure of development effort will be required to improve our understanding of these resources.

9 IMPACT OF TECHNOLOGY

9.1 Introduction

Over the life of the oil and gas industry, technological innovation and experience gained have significantly improved the efficiency of finding and developing hydrocarbon reserves. Technological change continues to take place such that reserves once considered uneconomic to develop at today's prices are now being tapped. It is, therefore, important to consider the impact of technology when evaluating Alberta's ultimate gas potential as innovation increases the size of the resource base.

Through geologic, engineering and economic evaluations, the amount of gas reserves that will be found and developed at a given price can be estimated. As discussed in Chapter 5, the relationship between price and ultimate resource potential is a positive one because as prices increase the more marginal resources become economic to develop. However, if the result of a technological improvement reduces exploration or development costs, the improvement may make a marginal reserve economic without an increase in gas price. Thus, any analysis that does not consider technological change runs the risk of underestimating the ultimate potential of the resource base.

9.2 Evidence of Technological Change

There are many areas of the gas industry where technological advancement is or may be occurring. Examples of specific advancements can be found throughout the literature. However, finding evidence of the impact of these advancements on a provincial basis is somewhat more difficult and quantifying that impact is very difficult.

Probably the most striking evidence of change is in drilling rates. Figure 9.1 shows the historical drilling rates both on a days per well and a metres drilled per day basis. This data, compiled from ERCB drilling records, reflects the number of days between the spud date and the finished drilling date of wells drilled in Alberta over the past several years.

Drilling cost data on a detailed enough basis for proper analysis is rather difficult to obtain. Figure 9.2 is a reasonably complete set of cost data for the Waterton Field. The data indicates that drilling costs are going down but the question remains as to whether the reduction is the result of technological advancement or of the several other factors influencing drilling cost.

Historical reserve additions per well and drilling success rates in Alberta are shown in Figures 9.3 and 9.4, respectively. Neither data set is very conclusive but one could speculate that the increase in both reserve additions per well and success rates in recent years is the result of technological improvement. Recent economic conditions have been such as to encourage efficiency and improvements in all aspects of the industry. Certainly, the geological opportunities are diminishing, or at least not improving, and one would have expected a decline in both these parameters.

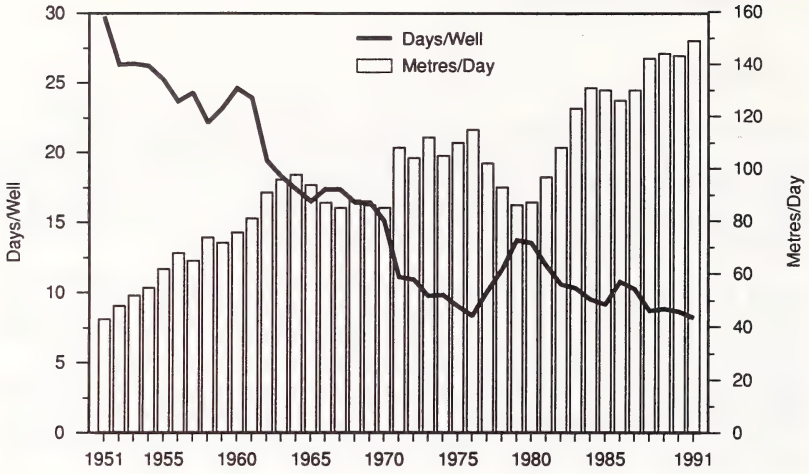


FIGURE 9.1 HISTORICAL DRILLING RATES

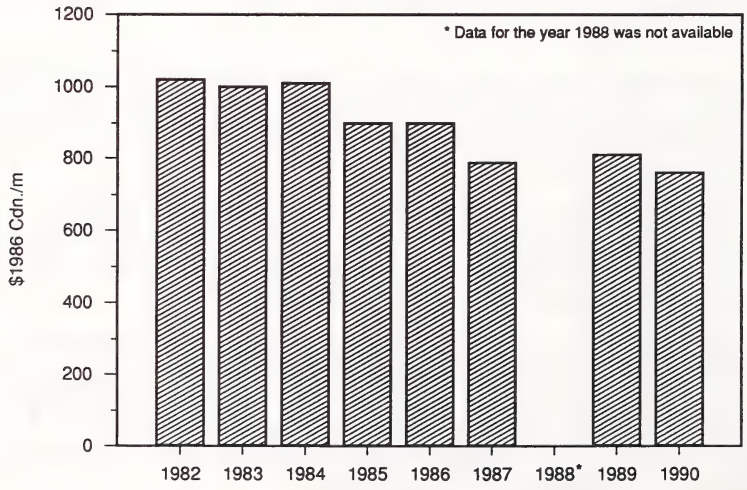


FIGURE 9.2 HISTORICAL DRILLING COSTS IN WATERTON FIELD

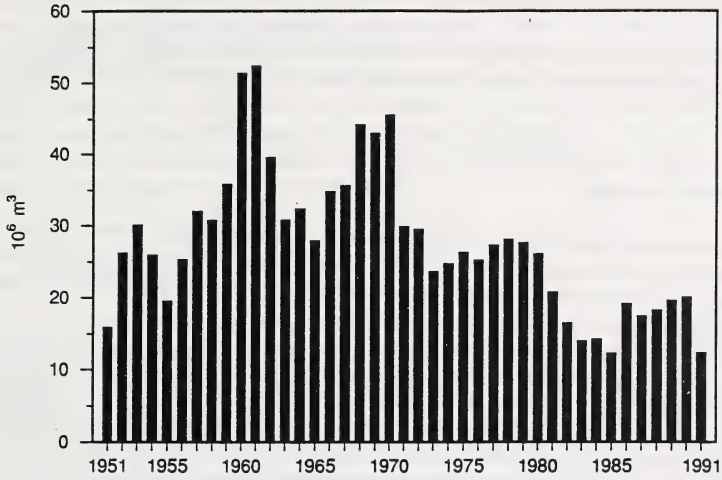


FIGURE 9.3 HISTORICAL RESERVE ADDITIONS PER WELL

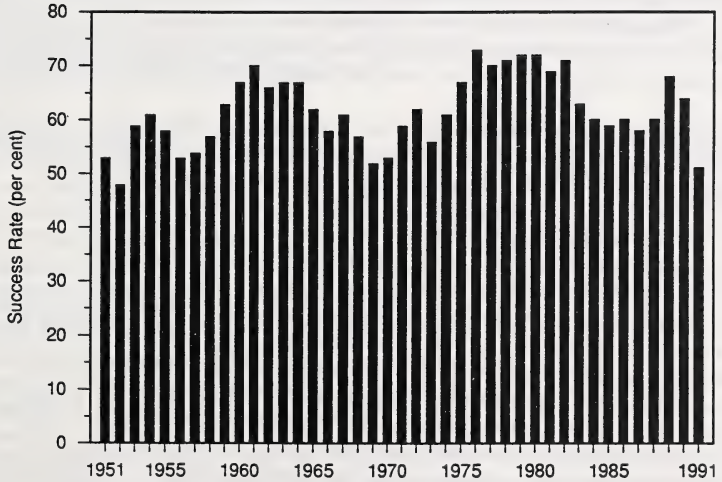


FIGURE 9.4 HISTORICAL DRILLING SUCCESS RATE

9.3 Specific Technological Advancements

In meetings between industry and Board staff, certain technologies were identified as having significant impact on the costs of exploration and development. These technologies are discussed below.

9.3.1 Drill Bit Technology

Over time, technological breakthroughs in drill bit technology have resulted in dramatic improvements in performance and, consequently, have reduced drilling costs. The more durable the drill bit, the less frequently the operator has to trip out of the well to replace the bit, thus minimizing the time that the drilling rig stands idle.

While three cone rolling cutter rock bits have been available to drillers for a number of decades, a significant step forward was the introduction of the Tungsten Carbide Insert (TCI) cutting element for rolling cutter bits. More recent technology that has increased drilling efficiency is the development of Polycrystalline Diamond Compact (PDC) technology. Forming PDC is a liquid phase sintering operation. Diamond powder (graphite) is mixed with a catalyst binder and is subjected to pressures of 750 000 psi and temperatures in excess of 1400 °C. PDC has many advantages over TCI including a much higher wear ratio and greater thermal conductivity.

More recent developments enhancing PDC technology include bonding PDC wafers to a curved tungsten carbide substrate. (Formerly, PDC wafers could only be bonded to flat tungsten carbide surfaces). This type of drill bit has been intensively tested in Alberta, with one test in the Peace River region yielding cost savings in excess of $3.00 per metre. Horizontal wells have been drilled in Northwestern Alberta with the enhanced PDC drill bit, and operators have been able to complete these wells with longer bit runs, and reduced wear on downhole equipment by maintaining gauge hole.

PDC technology has also been applied to create more durable bearings for the roller cone. Combining enhanced inserts and PDC bearings will create a roller cone bit capable of drilling at much higher rates of penetration than was previously possible.

9.3.2 Drilling Mud

Technological advances in developing drilling fluids (muds) have had, and will continue to have, significant cost saving effects. In areas which have shales with a high content of swelling clays, drilling fluids tend to deteriorate as the mud's weight and viscosity increases from dispersed drilled solids. When this happens, the drilling mud must be changed frequently which can be an expensive proposition. Even more serious is the damage which may occur due to the introduction of mud to the formation. Formation damage can be defined as the alteration of the producing formation near the wellbore due to the introduction of foreign fluids. This usually happens as the fluid forms an emulsion or when fine particles are deposited in pore throats, thus reducing permeability. The consequence of formation damage is often a much lower well productivity.

The introduction of water based polymeric fluids and inorganic drilling fluid additives, have gone a long way to alleviating some of the problems described above. These new drilling fluids are less prone to viscosity increases when drilling in regions containing swelling clays, and formation damage is also minimized. Large cost savings can result when a well can be brought on production without having to be cleaned and/or perforated beyond the damage zone. In Alberta, wells drilled in Lindbergh shales which have high contents of swelling clays have experienced large cost savings when using drilling muds with inorganic drilling fluid additives. The evolution of new drilling muds will continue to reduce drilling costs and formation damage.

9.3.3 Horizontal Drilling

Horizontal drilling involves drilling horizontally along the pay interval in order to expose as much reservoir as possible to the wellbore and thereby increase productivity of the well. Horizontal drilling could potentially have a major impact on recovery of marginal reserves particularly where low permeability is a problem. While Canada's first horizontal well was drilled in 1978, these wells were very rare until recent advances in drill bit technology and measuring while drilling instruments (MWD) reduced the costs of drilling horizontally. By the end of 1990, only twelve gas wells had been drilled horizontally in Alberta. This number is expected to increase dramatically as the associated costs continue to fall.

Horizontal drilling can reduce development costs as the resistance to flow around a horizontal well is lower than that around a vertical well, so fewer wells are necessary to achieve the same reservoir drainage. Horizontal wells are particularly advantageous where the reservoir contains natural vertical fractures. In these cases, the well intersects the fractures perpendicular to their surfaces and this can result in improved productivity and reduced coning problems. Horizontal drilling offers other potential applications as this technique could enable producers to reach reserves under lakes or under urban areas that were previously unattainable.

Associated technological developments that have contributed to the success and/or cost effectiveness of horizontal drilling include downhole mud motors, MWD instruments, and PDC drill bit technology. The use of downhole motors facilitates directional drilling as steering is achieved by orienting the drill pipe so that the bend from the "tool face" is in the desired direction. The use of MWD instruments enables drillers to locate the position of the bottom of the hole and the direction of advance. The combination of MWD instruments and PDC drill bits provides for the drilling of large portions of the horizontal well without tripping to replace equipment or ascertain downhole drill bit location. Thus, large cost savings are realized.

9.3.4 Seismic

Technological improvements in seismic surveying have increased the efficiency of finding hydrocarbon deposits and improved field development to maximize resource recovery while minimizing costs. The introduction of 3-D seismic, in particular, has helped geophysicists interpret plays with greater accuracy as this method provides better control over structural shape than 2-D seismic and improves

the ability to map stratigraphic variations in detail. While a 2-D seismic shoot involves the arrangement of geophones in a straight line, 3-D seismic requires geophones to be laid out in a grid-like formation. Increased up-front costs are involved in data collection for 3-D seismic because it typically involves more shot points and receiver lines than does the more conventional 2-D seismic.

Advances in computer technology have increased the accessibility to 3-D seismic surveys which utilize computers extensively to process data and generate 3-D images of geologic formations. As a 3-D seismic survey also provides more detail about a reservoir than a 2-D survey, an investment in this technology will typically result in fewer development dry holes and improve placement of drilling locations to maximize hydrocarbon recovery. In addition, new drilling opportunities may be identified.

The 3-D surveys conducted in Alberta have proven the technique to be a cost-effective tool. One such survey, conducted in the Black Creek basin of Northwestern Alberta where several pinnacle reefs are typically found in a single square mile, found 3-D seismic to be particularly cost effective. A well in the area costs about twenty times the amount of acquiring and processing 3-D seismic data for a square mile. Thus, 3-D seismic dramatically reduced dry hole costs.

9.4 Conclusions

The Board expects that the technologies discussed above, and perhaps other technologies, will continue to play an increasing role in the development of Alberta's gas resources. As the sedimentary basin becomes more mature and marginal reserves become an important part of the supply picture, technology takes on an increasing role.

The Board's estimates of ultimate potential assume only moderate, foreseeable improvements in technology. To the extent that significant, unforeseen improvements in technology are realized, there will be additional reserves available.

10 CONCLUSIONS

The Board's minimum case or most pessimistic estimate of the gas resource in place for Alberta is some 8000 $\times$ 10^9 m^3 (280 Tcf) and the maximum case or most optimistic estimate is 12 700 $\times$ 10^9 m^3 (450 Tcf). The medium case or best guess estimate is some 9600 $\times$ 10^9 m^3 (340 Tcf). On a marketable gas basis at 37.4 MJ/m^3, these figures are 4770, 5740, and 7570 $\times$ 10^9 m^3 (170, 204, and 270 Tcf), respectively.

For the medium case resource in place estimate, the Board's economic analysis suggests that some 71% of the yet to be discovered resource could be economically developed at a gas price of $3.00/GJ. This percentage increases to some 87% at $5.00/GJ. In order to achieve economic recovery at or above 98% of the estimated resource, a price exceeding $10.00/GJ would be necessary. These percentages assume no improvement in current technology.

The wide range in estimates of ultimate gas in place reflect the difficulty in predicting the geological potential. Further, uncertainties with respect to future technological advances and economic conditions cast considerable doubt on estimates of the portion of this potential which is realistically recoverable. Having regard for these uncertainties, the Board considers an ultimate potential for gas of 5600 $\times$ 10^9 m^3 (200 Tcf) at 37.4 MJ/m^3 to be a realistic estimate upon which to base policy decisions and forecasts at the current time.

The Board's analysis of supply and demand suggests that gas production will increase steadily to a level of some 120 $\times$ 10^9 m^3 per year by the turn of the century. At that time, supply from conventional gas sources may begin to decline and supply from other sources may be required to meet the total demand for Alberta gas. However, these projections are based on the Medium Case estimate of ultimate gas in place and on reasonably foreseeable economic and technological changes. Should the resource base prove to be larger or significant improvements in economics or technology be realized, conventional gas could meet demand well into the next century.

With respect to unconventional gas, there is little doubt that the resource potential is very large for both coalbed methane and tight gas. However, improvements in gas price or technology are required before significant production from these sources will be realized. Near the turn of the century as supply from conventional gas begins to decline, the Board anticipates that gas prices will increase enough to justify development of unconventional sources. Unconventional gas will likely be developed to meet a portion and perhaps all of the supply shortfall. The unconventional resource base is very substantial and should provide for consumer needs far into the next century.

The Board's analysis of ultimate potential for gas and the economics of producing the gas suggest that significant potential remains for further gas discoveries in Alberta. The gas industry, both conventional and unconventional, will likely dominate the oil and gas industry and remain a significant part of the province's economy for many decades.

APPENDIX A GENERAL BULLETIN GB 90-11

ERCB

Energy Resources Conservation Board

640 Fifth Avenue SW
Calgary, Alberta
Canada T2P 3G4

General Bulletin

GB 90-11

To: ALL OIL AND GAS OPERATORS 20 June 1990

PROCEEDING NO. 900800
ULTIMATE POTENTIAL AND SUPPLY OF NATURAL GAS - 1990 REVIEW

CALL FOR SUBMISSIONS

The Energy Resources Conservation Board is currently assessing Alberta's long-term natural gas supply with particular emphasis on the ultimate potential for gas within Alberta. The last similar review was carried out by the Board in 1978 and published in ERCB Report 79-G. The primary objective of the current analysis is to prepare a comprehensive update of Alberta's total gas potential in light of expected economic conditions, full consideration of anticipated geological prospects, and technological circumstances. The Board would welcome industry submissions to assist in this analysis.

The Board would appreciate receiving submissions on one or more of the following topics:

1. Ultimate potential for gas in Alberta
   - Appreciation of reserves considered proved as of 31 December 1989 and reported on in ERCB Report ST 90-18,
   - new discoveries, and
   - unconventional gas (gas from ultra-low permeability reservoirs, coalbed methane, etc).

2. Economic outlook
   - outlook for future oil and gas prices, and
   - trends in exploration, development, finding, and operating costs.

3. Gas supply
   - potential supplies of gas from established reserves,
   - anticipated rate of reserves additions and connection,
   - potential supplies of gas from reserves yet to be discovered, and
   - potential supplies of gas from unconventional sources.

While the Board does not wish to restrict the content of submissions, for convenience it asks that

1. all ultimate potential estimates be on an initial basis - ie. before production,

2. reserve estimates be clearly identified as in-place raw gas and recoverable marketable gas,

3. to the extent practical, estimates be supported by discussions of geological setting, results of recent exploration, trends in exploration and production technology, and expected reservoir conditions such as size, entrapment, rock quality and depth,

4. estimates of ultimate potential and supply of unconventional gas be accompanied by details respecting major assumptions such as gas price required to make such resources economically viable, exploration, development and production costs, and the technology involved, and

5. supply forecasts be on an annual basis for the period 1991 to 2005 and be accompanied by details respecting major assumptions such as gas price, costs, industry activity, well deliverabilities, contract rates-of-take, and production profiles. Submittors are also invited to comment on the longer-term implications of their ultimate potential estimates and supply forecasts.

Although the above guidelines refer to the entire province, the Board would welcome any submission which addressed itself only to specific areas, formations, or reserve types. An example of an area which may require special study is the Alberta foothills region.

It is expected that follow-up regarding these submissions will be limited to informal inquiries or technical meetings between the Board staff and submittors after the submissions have been received and reviewed.

A copy of each submission will be made available for public scrutiny in the Board's Information Services by reference to Proceeding No. 900800, "ULTIMATE POTENTIAL AND SUPPLY OF NATURAL GAS - 1990 REVIEW". The Board's findings will be released in a public report.

Any person wishing to make a submission should make known his intent on or before 1 September 1990 and is requested to file on or before 15 December 1990 seven copies of his submission with the Board (Attention: Harvey Halladay, Gas Department) 640 - 5 Avenue S.W., Calgary, Alberta, T2P 3G4. Any questions or discussions regarding this matter should be directed to Mr. Halladay at (403) 297-8291.

F. J. Mink
Board Member

APPENDIX B ABBREVIATIONS AND TERMINOLOGY

B.1 Abbreviations

2-D	two dimensional (used in reference to seismic)
3-D	three dimensional (used in reference to seismic)
APIP	Alberta Petroleum Incentives Program
ARC	Alberta Research Council
bbl	barrel
Bcf	billion cubic feet
BER	beyond economic reach
C_1	methane
C_2	ethane
C_3	propane
C_5	pentanes
C_6	hexanes
C_7+	heptanes plus
cf	cubic foot
CO_2	carbon dioxide
CPA	Canadian Petroleum Association
ERCB	Energy Resources Conservation Board
Estab.	established
G&G	geological and geophysical
GCA	gas cost allowance
GIP	gas in place
GIP/sec	gas in place per section
GJ	gigajoule
GRC	gas resource category
H_2	hydrogen
H_2S	hydrogen sulphide
He	helium
Hvb	high-volatile bituminous
iC_4	iso-butane
IGIP	initial gas in place
IMG	initial marketable gas
IPAC	Independent Petroleum Association of Canada
Log	logarithm
Lvb	low-volatile bituminous
m	metre
Mcf	thousand cubic feet
MJ	megajoule
Mvb	medium-volatile bituminous
MWD	measuring while drilling
N_2	nitrogen

nC_4	normal butane
NOVA	Nova Corporation of Alberta
PDC	polycrystalline diamond compact
PGC	Potential Gas Committee
PSAC	Petroleum Services Association of Canada
RR/P	remaining reserves to production ratio
Sb	subbituminous
Sproule	Sproule Associates Limited
t	tonnes
Tcf	trillion cubic feet
TCI	tungsten carbide insert
TCPL	TransCanada PipeLines Limited
US	United States of America
WCSB	Western Canadian Sedimentary Basin
WGML	Western Gas Marketing Limited

B.2 Terminology

In addition to the terms defined in this section there have been a few economics terms and many geological terms used in this report. The reader is asked to consult a textbook or dictionary from the appropriate discipline for definitions of these terms.

Associated Gas	Gas in a free state in communication in a reservoir with crude oil, under initial reservoir conditions.
Beyond Economic Reach Reserves	Reserves which are not considered to be economic to produce given current gas prices, capital costs of required facilities, and production costs.
Coalbed Methane	The naturally occurring, dry, predominately methane gas produced during the transformation of organic material into coal. It is present within the molecular structure of all coals, as gas in matrix porosity, as free gas in open fractures in coal, and as gas dissolved in ground water within the coal. (See also Section 8.2 in this report).
Commercial Scenario	As used in this report, the scenario presented in the Board's economic studies which assumes a full tax and royalty burdened regime (see also, Economic Scenario and No Royalty Scenario).
Conventional Natural Gas	Natural gas occurring in a normal porous and permeable reservoir rock which at a particular point in time can be technically and economically produced using normal production practices (see also, Unconventional Natural Gas and Section 2.1 of this report).

Cycling Pools — A natural gas reservoir in which the raw gas contains significant quantities of ethane and heavier hydrocarbons which would, at least partially, condense and remain in the reservoir under normal depletion practices. The cycling process involves injecting dry natural gas into the reservoir to prevent the loss of these heavier hydrocarbons.

Deep Basin — The volume of sediments underlying a very large, loosely defined area along the eastern side of the Rocky Mountains extending from south-central Alberta to northern British Columbia. (see also, ------ 1984. Lower Cretaceous Oil and Gas in Western Canada. In: Deep Basin Gas, J.A. Masters (ed.). **American Association of Petroleum Geologists Memoir 38,** p. 1-34.)

Deferred Reserves — Associated gas which provides a drive mechanism for oil recovery and which, therefore, is not produced until the oil is depleted.

Economic Scenario — As used in this report, the scenario presented in the Board's economic studies which assumes a tax and royalty free regime (see also, Commercial Scenario and No Royalty Scenario).

Established Reserves — Those reserves recoverable under current technology and present and anticipated economic conditions, specifically proved by drilling, testing, or production; plus that judgement portion of contiguous recoverable reserves that are interpreted from geological, geophysical, or similar information, with reasonable certainty to exist.

Full Cycle Economics — As used in this report, the economic analysis case which includes all costs in the cash flow analysis. These costs include land, G&G, drilling and completion of both exploratory and development wells, production, and abandonment costs (see also, Half Cycle Economics).

Future Gas — Gas which will, in future, be added to established reserves through extensions and revisions to existing pools and the discovery of new pools but which has not as yet been specifically proved by drilling, testing, or production. Future gas is the difference between ultimate potential and initial established reserves. (Also referred to as Yet to be Established or Yet to be Discovered Gas).

Gas — Raw gas or marketable gas or any constituent of raw gas, condensate, crude bitumen, or crude oil that is recovered in processing and that is gaseous at the conditions under which its volume is measured or estimated.

Gas Equivalent of Oil — The volume of gas which is equivalent, on an economic basis, to finding one unit volume of oil. In this report, finding 2660 cubic metres of gas is assumed to be economically equivalent to finding one cubic metre of oil.

Gas In Place	The volume of natural gas calculated or interpreted to exist in a reservoir.
Gas Resource Category	As used in this report, three distinct categories of future gas defined in terms of the probability of encountering gas. This probability is a function of geologic setting, reservoir type and distance from established reserves.
Gas Saturation	The fraction of pore space in the reservoir rock occupied by gas upon discovery.
Half Cycle Economics	As used in this report, the economic analysis case which excludes land, G&G, and drilling and completion of exploratory well costs in the cash flow analysis (see also, Full Cycle Economics).
Inch-mile	As used in this report, the diameter of a pipeline measured in inches times its length in miles. Used in estimating gas pipeline costs.
Initial Established Reserves	Established reserves prior to the deduction of any production.
Remaining Established Reserves	Initial established reserves less cumulative production.
Initial Gas In Place	The gross volume of raw natural gas calculated or interpreted to exist in a reservoir before any volume has been produced.
Injection Pools	Reservoirs into which natural gas is injected as a drive mechanism to increase oil recovery. To the extent feasible, the gas will be produced and used after the oil is depleted.
Lahee Classification	A system of well classification used to identify whether a well is exploratory, development or other classification (see ERCB Informational Letter 86-4).
Marketable Gas	A mixture mainly of methane originating from raw gas, if necessary through the processing of the raw gas for the removal or partial removal of some constituents, and which meets specifications for use as a domestic, commercial, or industrial fuel or as an industrial raw material.
Non-Associated Gas	Gas that is not in communication in a reservoir with an accumulation of liquid hydrocarbons at initial reservoir conditions.
No Royalty Scenario	As used in this report, the scenario presented in the Board's economic studies which assumes full taxes but no royalties apply (see also, Commercial Scenario and Economic Scenario).

Rate of Take — A term used to describe gas purchase contract rates or production rates on the basis of the reserves dedicated to the contract or in the production unit. Rate of take is expressed as one unit per day of production per multiple units of reserves (e.g. a 1/7300 rate of take is one unit per day of production for each 7300 units of reserves. Constant production at this rate would result in a 20 year producing life for the reserve.)

Raw Gas — A mixture containing methane, other paraffinic hydrocarbons, nitrogen, carbon dioxide, hydrogen sulphide, helium, and minor impurities, or some of them, which is recovered or is recoverable at a well from an underground reservoir and which is gaseous at the conditions under which its volume is measured or estimated.

Recovery Factor — In gas pools, the fraction of the in-place reserves of gas expected to be recovered under the subsisting recovery mechanism.

Southeastern Alberta Shallow Gas Pools — The Milk River, Medicine Hat and Second White Specks pools of southeastern Alberta. (Includes some smaller pools combined with these pools for production accounting purposes.)

Solution Gas — Gas that is dissolved in crude oil under reservoir conditions and evolves as a result of pressure and temperature changes.

Success Rate — The percentage of total wells drilled which actually discover reserves. Success rate can be applied to oil or gas wells or a combination of oil and gas wells.

Surface Loss — A summation of the fractions of recoverable gas that is removed as acid gas and liquid hydrocarbons, used as lease or plant fuel, or flared.

Tight Gas — Natural gas contained in ultra low permeability gas reservoirs (see also Sections 2.1 and 8.1 of this report).

Ultimate Potential — An estimate of the initial established reserves that will have been developed in an area by the time all exploratory and development activity has ceased, having regard for the geological prospects of that area and anticipated technology and economic conditions.

Ultimate potential includes cumulative production, remaining established reserves, and future additions through extensions and revisions to existing pools and the discovery of new pools. Ultimate potential can be expressed by the following simple formula:

Ultimate potential = initial established reserves
+ additions to existing pools
+ future discoveries.

Unconventional Natural Gas	Natural gas which is not classified as conventional natural gas. The unconventional natural gas types discussed in this report are tight gas and coalbed methane (see also, Conventional Natural Gas and Section 2.1 of this report).
Yet to be Discovered	Gas which will, in future, be added to established reserves through extensions and revisions to existing pools and the discovery of new pools but which has not as yet been specifically proved by drilling, testing, or production. Yet to be discovered gas is the difference between ultimate potential and initial established reserves. (Also referred to as Future Gas or Yet to be Established Gas).
Yet to be Established	Gas which will, in future, be added to established reserves through extensions and revisions to existing pools and the discovery of new pools but which has not as yet been specifically proved by drilling, testing, or production. Yet to be established gas is the difference between ultimate potential and initial established reserves. (Also referred to as Future Gas or Yet to be Discovered Gas).

APPENDIX C INDUSTRY INPUT

In October of 1990, the Board issued General Bulletin GB 90-11 requesting that industry provide input to the Board's review of ultimate potential and gas supply. Four companies made formal submissions to the Board in response to that bulletin:

- Alberta Research Council (ARC)
- NOVA Corporation of Alberta (NOVA)
- TransCanada PipeLines Limited (TCPL)
- Western Gas Marketing Limited (WGML)

Due to the limited response to GB 90-11, the Board staff contacted several major gas producing companies and asked that they provide input on an informal, general discussion basis. Eight companies and the Canadian Petroleum Association agreed to meet with ERCB staff to discuss ultimate potential and future gas supply in Alberta.

This chapter provides a brief overview of the four formal submissions and the input provided through the Board staff meetings.

C.1 Formal Submissions

The four formal submissions may be viewed in the Information Services Section at the ERCB's head office in Calgary, Alberta. The following is a brief summary of these submissions.

C.1.1 Alberta Research Council

The ARC submission dealt only with coalbed methane. ARC divided its estimates of the amount of coal, the gas content of the coal, and the ultimate potential gas resource into three sub-divisions based on coal rank:

(1) High-volatile bituminous (Hvb) plus Subbituminous (Sb),
(2) Medium-volatile bituminous (Mvb), and
(3) Low-volatile bituminous (Lvb).

The ARC estimates that the total ultimate potential for recoverable coalbed methane in Alberta is some 73.5×10^{12} m^3 (2600 Tcf). The breakdown of this total by coal rank is presented in Table C.1. ARC also presented an economic subdivision of the resource based on dollar ranges for gas delivered to a pipeline system as shown in Table C.2. These estimates are based on assumptions relating to hydrostatic pressures, permeability, water and gas saturations, and waste water disposal costs.

TABLE C.1 Coalbed Methane Resources – Alberta Research Council

Coal Rank	Coal Resource 10^{12} tonnes	Gas Content m^3/tonne	Gas Resource 10^{12} m^3
Hvb + Sb	3.0	11	33.0
Mvb	1.5	13	19.5
Lvb	1.5	14	21.0
Total	6.0		73.5

TABLE C.2 Coalbed Methane Cost Groups – Alberta Research Council

Cost $/$10^3$ m^3 ($/Mcf)	Mvb + Lvb 10^{12} m^3	Hvb 10^{12} m^3	Total 10^{12} m^3
$61.84-$88.34 ($1.75-$2.50)	20.5	8.25	28.75
$88.34-$176.68 ($2.50-$5.00)	20.5	16.50	37.00
>$176.68 (>$5.00)	-	8.25	8.25
Total	41.0	33.00	74.00

C.1.2 NOVA Corporation of Alberta

NOVA submitted a study entitled "Ultimate Potential and Supply of Natural Gas – 1990 Review". The study included a forecast of expected gas production from conventional sources, subdivided as to production from remaining established reserves and reserves additions. The forecast is reproduced from NOVA's submission as Figure C.1 in this report.

The price forecasts underlying NOVA's study assumed a "return to moderately priced oil" and that natural gas prices would rise somewhat relative to crude oil prices. The following is a summary of NOVA's findings and conclusions in the four main areas upon which its study focused.

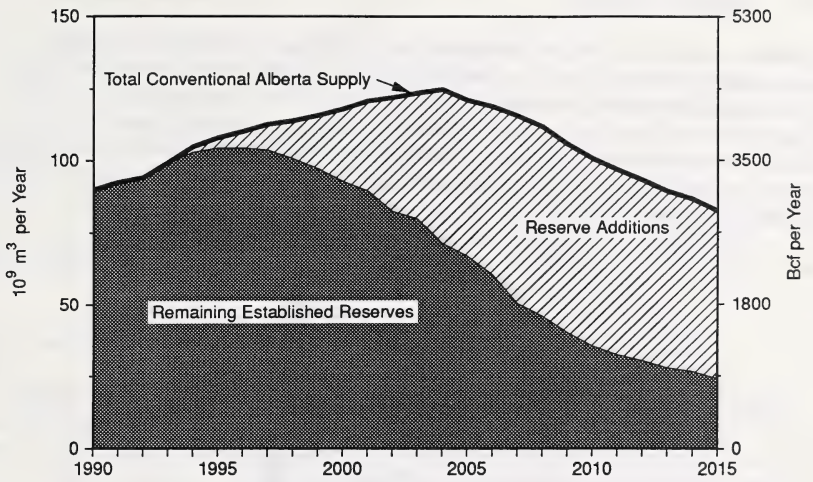


FIGURE C.1 ANNUAL ALBERTA CONVENTIONAL SUPPLY - NOVA

C.1.2.1 Total Conventional Potential

NOVA conducts detailed reserves studies of many pools in support of its facility expansion applications to the ERCB. These studies suggest that, within the areas studied, there are 174×10^9 m^3 (6.2 Tcf) of reserves in addition to those recognized by the ERCB. These discrepancies reflect differences of opinion on the reserves contained in some pools. Shut-in reserves account for about 560×10^9 m^3 (20 Tcf) of the remaining marketable reserves. About one half of these reserves could be produced at wellhead prices less than $0.95/GJ ($1.00/Mcf) but one tenth would only become economic at prices above $2.37/GJ ($2.50/Mcf).

NOVA forecasts reserve additions using an aggregate model which portrays both drilling, as a response to economic conditions, and the discovery of additional reserves as a result of drilling activity. Annual reserve additions are forecast to start at just over 64×10^9 m^3 (2.3 Tcf) in 1990, rise gradually to levels of 70×10^9 m^3 (2.5 Tcf) by the late 1990s, and gradually fall to less than 55×10^9 m^3 (2.0 Tcf). Over the 25-year forecast, reserve additions are expected to total 1710×10^9 m^3 (60 Tcf).

Although NOVA did not specifically determine an ultimate potential number, its reserve additions forecast suggests an ultimate potential close to 5600×10^9 m^3 (200 Tcf). Technological improvements in areas such as horizontal drilling and three dimensional seismic could supplement NOVA's potential reserves estimates which do not consider such improved technologies.

C.1.2.2 Location of Reserves

For purposes of its study, NOVA divided the province into nine areas, "modified Potter-Liddle areas", as shown in Figure C.2. The southeastern portion of Alberta (areas 1, 2, and 3) holds about 35% of the initial gas reserves, and the northern areas (4 and 5) only a small portion. The western areas (6, 7, 8, and 9) including the Deep Basin and Foothills region contain the largest share and are expected to contribute an even larger share of the future reserves. Near-term activity levels will likely continue to concentrate in the southeastern areas but the emphasis will gradually shift to the western, higher supply cost areas.

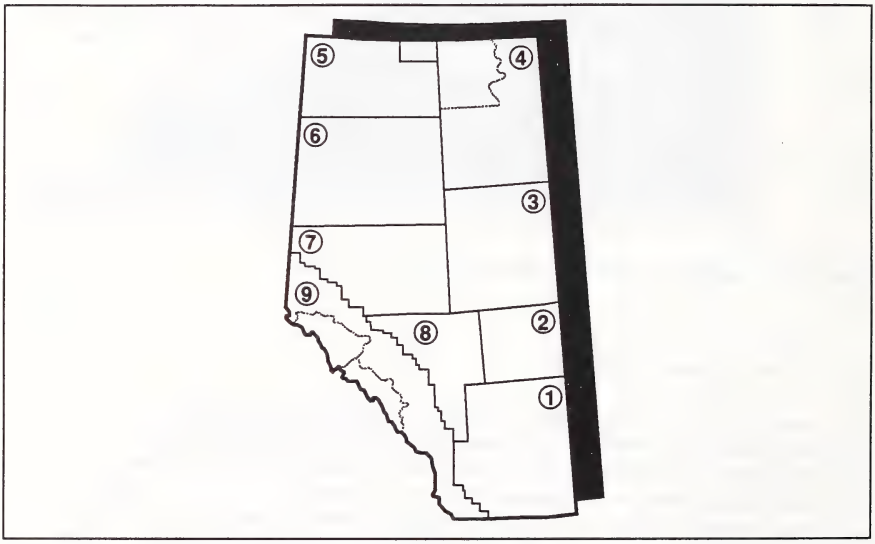


FIGURE C.2 MODIFIED POTTER - LIDDLE AREAS

C.1.2.3 Supply

NOVA estimates production flows from Alberta reserves by assessing individual reservoir economics and by considering transportation contracts at individual meter stations. Southeastern Alberta production is characterized by earlier connection rates, closer well spacing and higher rates of take than other areas of the province. Southeastern and central Alberta currently contribute 35% of Alberta's production while the Foothills and Deep Basin provide over 50%. NOVA anticipates a north-westerly shift in production flows over the next 25 years with the Foothills and Deep Basin continuing to contribute some 50%. Production from the north and northwestern areas will increase to about 20%.

C.1.2.4 Unconventional Reserves

NOVA expects tight gas deposits, primarily in the western area of the province, to become economic only at prices over $3.79/GJ ($4.00/Mcf) in 1989 Canadian dollars. Since this price is not expected to be achieved in the next 25 years, NOVA did not include tight gas in its estimate of ultimate potential. Coalbed methane is a potentially large supply of gas in Alberta with preliminary estimates suggesting about 1100×10^9 m^3 (39 Tcf) of coalbed methane resource. NOVA estimates that the cost of developing and producing these supplies will range from about $2.37/GJ to $4.74/GJ ($2.50 to $5.00/Mcf). Although NOVA anticipates that some coalbed methane could become economic within the decade, it did not include specific estimates of production or reserves due to the uncertainty respecting this supply source.

C.1.3 TransCanada PipeLines Limited

TCPL commissioned a study by Sproule Associates Limited (Sproule) entitled "The Future Natural Gas Supply Capability of Alberta" which it submitted in response to General Bulletin GB 90-11. The Sproule study investigated the natural gas supply capability of the conventional producing areas of Alberta through the year 2012. The primary focus of the study was on the reserve additions that will result from future exploration and development efforts. In conducting the study, Sproule used its predictive model (Sproule's Gas Supply Capability Model) which forecasts drilling activity and consequent gas reserve additions. Sproule also used its economic model (NEVAL) which assesses the internal rate of return that the predicted expenditures would generate.

Sproule's Gas Supply Capability Model is comprised of five major segments:

(1) Remaining Established Reserves
(2) Costs and Revenues
(3) Reserve Additions
(4) Deliverability Forecasts
(5) Drilling Success Rates

Sproule adopted the remaining established reserves estimates published by the Canadian Petroleum Association. For the remaining four factors, it conducted extensive, detailed analysis of historical data for both Canada and the United States (lower 48 states only). Sproule used the algorithms and conclusions developed in these analyses in formulating the predictive capability of its model. The natural gas demand scenario and crude oil and natural gas price forecasts used as input to the model were prepared independently by TCPL.

The reserve additions segment of the model generated a range of inferred ultimate potential for gas estimates. This range, 5.47×10^{12} m^3 to 6.51×10^{12} m^3 (194 to 231 Tcf), depends on the algorithm used to forecast reserve additions. Various algorithms were generated depending on the specific range of years used in the historical data analysis. The results of Sproule's base case analysis using the lower ultimate potential are presented in Figure C.3, reproduced from the submission. The figure

suggests that supply will be unable to meet demand by 2002. Sproule's analysis suggests that this shortfall would occur in about 2010 for the high ultimate potential case.

Sproule also conducted sensitivity analyses using a 1 unit per day of production per 3500 units of reserves (1/3500) rate of take rather than the 1/5000 rate of take used in the base case. The shortfall would occur in 2007 for the low ultimate potential case but would be delayed until after 2012 in the high case.

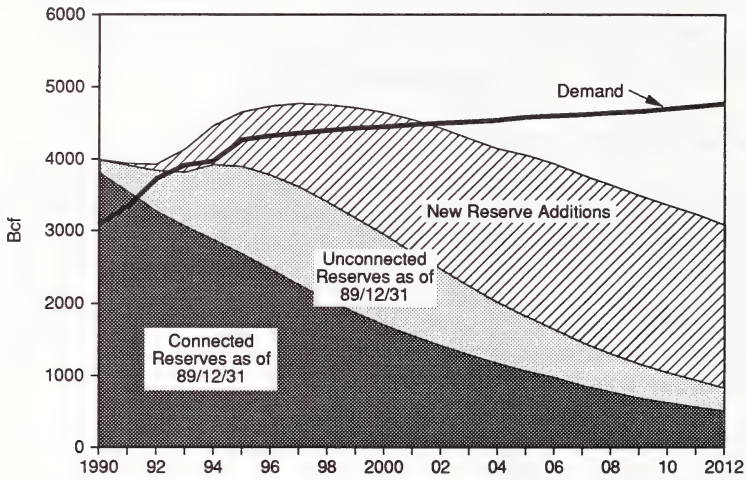


FIGURE C.3 PRODUCTION CAPACITY OF ALBERTA'S SEDIMENTARY BASIN
Base Case Demand Forecast

Sproule evaluated the cash flows predicted by its supply model to determine the return on capital employed for the demand case considered. Sproule compared these results to the petroleum industry's recent performance and concluded that the economics inherent in the model were reasonable and that the predicted levels of activity could be achieved.

In addition to the supply/demand analyses and estimates of ultimate potential, the Sproule study included a comprehensive set of forecast information on costs, revenues, gas co-product production, and drilling activity. The salient results of the historical data analyses are also included.

Although Sproule did not specifically deal with unconventional gas, it stated that these sources will become available over time as dictated by the available technology, economics and government incentives of the day.

C.1.4 Western Gas Marketing Limited

WGML submitted two studies. Although both studies had been completed some time ago (1987 and 1988), they were sufficiently current to be of benefit to the Board.

Study #1: Ultimate Gas Reserves Study, Western Canada Sedimentary Basin — April, 1987

In this study, WGML estimated the ultimate potential for gas in Alberta as well as in Northeastern British Columbia and Saskatchewan. The study also included a forecast of drilling and reserves additions to the year 2015 for the same areas. WGML's estimate of the ultimate potential for gas in Alberta was 6.87×10^{12} m^3 (244 Tcf).

WGML developed its estimate of ultimate potential using a methodology which extrapolates historical drilling performance. The province is divided into 10 areas for purposes of the analysis. The technique involves plotting, for each year end, the log of the discovered reserves divided by the cumulative gas well kilometreage versus the log of cumulative gas well kilometreage (log-log plots). A best fit of the most recent years' data is then extrapolated to an estimate of the ultimate gas well kilometreage for the area.

WGML found that eight of the ten areas yielded reasonable statistical correlations. There is limited gas potential in the two areas which did not yield reasonable correlations. The Alberta reserves estimates used in the study were those booked by the ERCB and the drilling statistics were obtained from the Canadian Petroleum Association. WGML estimated historical gas well kilometreage by adding the kilometreage of gas well completions to a portion of the dry and abandoned well kilometreage. The portion of dry and abandoned wells is based on the ratio of gas to oil completions. WGML estimated ultimate gas well kilometreage for each area by multiplying the number of sections by the wells per section and by the average well depths. The number of sections in each area are those assumed to be drillable in future. The wells per section is estimated on a judgement basis and the well depth is the average of existing wells in the area.

WGML tested the sensitivity of its results to various estimates of future gas well density as well as to the definition of gas well kilometreage (portion of dry and abandoned wells included). It found that the results were comparable to the base case estimate of ultimate potential.

WGML's submission also included forecasts of drilling and reserves growth for Alberta as shown in Table C.3. The forecast of gas well drilling is an extrapolation of the best fit line for a plot of cumulative gas well kilometreage for the most recent years prior to the 1987 study date. The cumulative reserves for each year were then read from the log-log plot for Alberta and the annual reserves additions were taken as the difference between successive year cumulative reserves.

TABLE C.3 Alberta Drilling and Reserves Growth – WGML Forecast

Year	Cumulative Gas Well Drilling (km)	Annual Reserves Additions (10^9 m^3)	Cumulative Reserves (10^9 m^3)
1990	78 000	560	3 610
1995	94 900	400	4 010
2000	111 800	320	4 330
2005	128 700	320	4 650
2010	145 600	290	4 950
2015	162 500	290	5 240

Study #2: Capability and Requirement Scenarios of the Western Canada Sedimentary Basin. October, 1988

This study presents several gas requirement and supply capability cases and estimates the length of time that supply can meet demand under each of these scenarios. The study was done for the entire Western Canadian Sedimentary Basin (WCSB) and no specific attempt was made to break the analysis out on a provincial basis.

WGML included five requirement scenarios using the current (1988) production level as the base case and adding increments to this base case. The first increment assumes continuation of historical growth patterns in WCSB production and the other three assume incremental increases in export requirements in 1989/90, 1990/91 and 1992/93.

WGML developed several supply scenarios using three drilling forecasts and three estimates of the remaining reserves to production ratio (RR/P). The low drilling forecast is taken as the average of the five lowest consecutive annual kilometreages between 1975 and 1987. The high drilling forecast is taken as the average of the five highest consecutive annual kilometreages between 1975 and 1987. The mid drilling forecast is the average annual kilometreages for these years. The reserves growth forecast corresponding to each of these drilling forecasts is derived using the reserves per kilometre estimates from the log-log plots in WGML's Study #1. RR/P ratios of 10, 15 and 20 are used.

The WGML submission presents the results of all combinations of these requirement and capability cases. Figure C.4, extracted from the submission, presents an overview of the various scenarios.

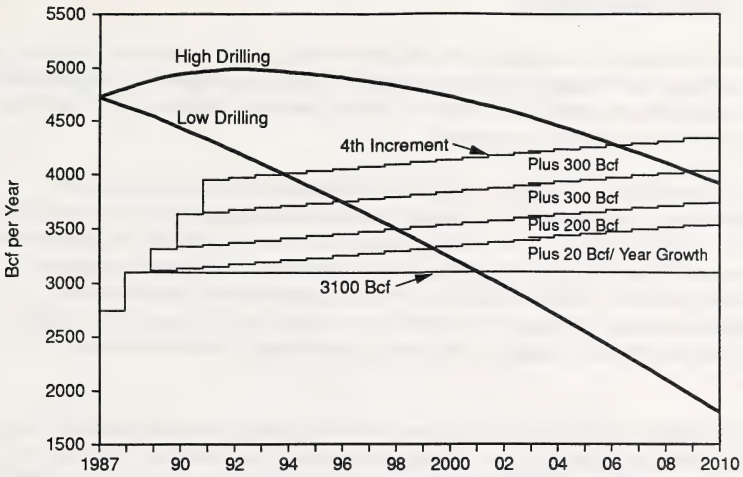


FIGURE C.4 REQUIREMENTS vs CAPABILITIES SCENARIOS - WGML (Using RR/P = 15)

C.2 Informal Input

The following is a list of the organizations with whom the Board staff held informal discussions or received information on ultimate potential or future gas supply in Alberta:

- Alberta Energy Company Ltd.
- Amoco Canada Petroleum Company, Ltd.
- Canadian Hunter Exploration Ltd.
- Canadian Petroleum Association
- Chevron Canada Resources
- ESSO Resources Canada Limited
- Gulf Canada Resources Limited
- Petro-Canada
- Shell Canada Limited

With few exceptions, these companies do not conduct extensive analyses of the ultimate potential for or supply of gas in Alberta, either from a provincial or sedimentary basin view point. Most companies have been forced to concentrate on specific areas where they have land holdings and are actively exploring for gas or oil. Several companies indicated that this narrower view of the business is a function of economics and is certainly a departure from the view they held during the Board's

1978 study. At that time, they had funds and staff available to take a more global, research-oriented interest in the entire sedimentary basin.

There is also more emphasis on competitive advantage and several companies cited this as a reason for not wanting to discuss their findings and conclusions publicly. Thus, as requested by the participating companies, the overview presented in this section will include ranges of estimates and will not tie any comments or observations to specific companies.

The few companies which prepared their own estimates of ultimate potential had done detailed geological analysis on a play-by-play basis, generally assuming some minimum pool size in the order of 50 to 100 $\times$ 10^6 m^3 (2 to 3 Bcf). Such studies require significant staff time and, consequently, are not undertaken very frequently. Most companies relied on consultants or published information respecting ultimate potential. Those companies which had not prepared their own estimates of ultimate potential were asked to comment on the ERCB's current estimate of some 4.8 $\times$ 10^{12} m^3 (170 Tcf). While most felt this estimate was reasonable, some thought it may be somewhat conservative.

Most companies pointed to the Foothills areas of the province as holding the most potential for future gas discoveries. The major difficulty is the very high cost involved in working in these areas. In some parts of the province, particularly the southeastern portion, "land fragmentation" was pointed to as a growing problem. This problem arises where only a few sections of land are available making it impossible to assemble a large enough parcel of land to provide for an economically viable project.

Much of the industries' recent focus is in consolidation of holdings and concentrating the company's efforts in the particular areas of endeavour perceived to be the most rewarding. This leads to sale or exchange of assets rather than pursuit of new exploration programs such that less effort is being expended in developing new gas plays. There is a shift to smaller, leaner, more efficient companies.

Forecasts of gas pricing in the near to intermediate term are quite pessimistic. Gas demand is expected to experience some growth but there is concern that the US, particularly as a result of unconventional gas subsidies, may be able to supply much of its own requirements for quite some time. Most supply forecasting is done on a reserve to production ratio basis with few companies endeavouring to do detailed modelling of gas supply or demand.

One of the few areas of optimism is in technological advancement. Several companies spoke with pride of their achievements in cost cutting measures in drilling. These measures included improved bit technology, new drilling muds, better mud centrifuges, better completion techniques, use of horizontal wells and improved, cost-conscious management of drilling programs. Success rates in some areas of the province are very high as a result of seismic reliability. Three dimensional seismic is promising but has the disadvantages of being expensive and difficult to apply in many areas for environmental reasons.

Few companies have done much work since the early 1980s on tight gas and few have done any work at all on coalbed methane. Several companies suggested that there are still many opportunities for conventional gas development. They are not likely to venture into unconventional gas projects until they begin to see limitations in conventional gas opportunities.

APPENDIX D GEOLOGY OF STRATIGRAPHIC INTERVALS

Introduction

This appendix discusses each of the thirty six stratigraphic intervals as defined in Chapter 3.

The description of each stratigraphic interval contains:

(1) A map showing the distribution of oil and gas reserves on a section basis. For convenience a few maps contain several stratigraphic intervals of roughly the same age. The maps are page size versions of the large maps which are included with this report under separate cover. However, the reduction process has caused minor distortion in these page size maps. The reader is encouraged to consult the large maps for accurate reserve locations as well as the additional information contained on the large maps.

(2) Reservoir parameters for the stratigraphic interval on a provincial basis.

(3) A table indicating the proven, undiscovered and ultimate potential gas in place.

The stratigraphic intervals are further subdivided into play areas which are described as follows:

(1) The play area name with an example field where possible.

(2) Reserve tables showing gas in place for pools greater than two sections and pools less than two sections.

(3) A brief geological discussion of the salient points of the formation, group or member.

(4) A geological estimate of the undiscovered gas volume for the Medium Case.

(5) A subjective estimate of the undiscovered pool size based on the remaining undrilled contiguous area and geological setting.

A list of the references used in preparing this appendix is included at the end of the appendix.

PASKAPOO AND EDMONTON INTERVAL

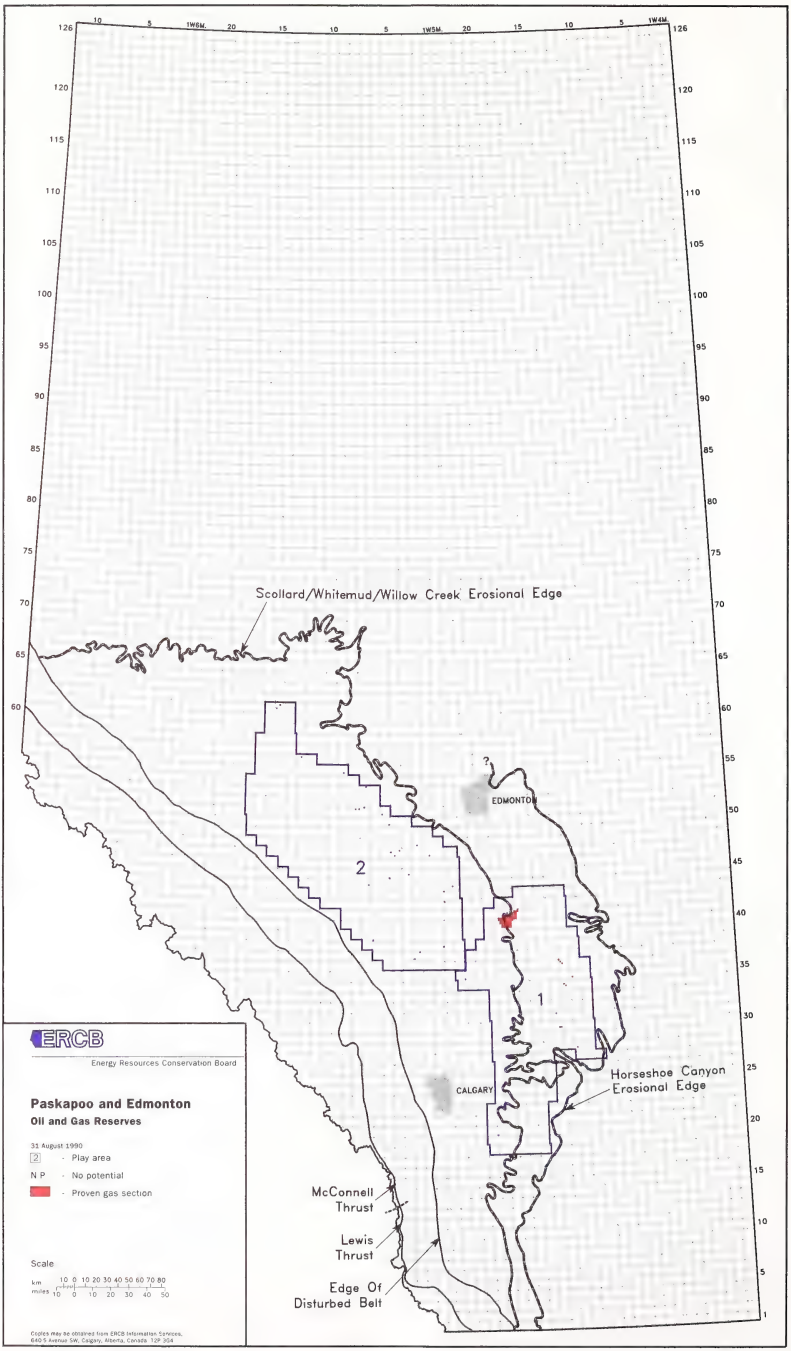

Scollard/Whitemud/Willow Creek Erosional Edge
EDMONTON
CALGARY
2
1
Horseshoe Canyon
Erosional Edge
McConnell
Thrust
Lewis
Thrust
Edge Of
Disturbed Belt
ERCB
Energy Resources Conservation Board
Paskapoo and Edmonton
Oil and Gas Reserves
31 August 1990
2 - Play area
N.P - No potential
- Proven gas section
Scale
km 10 0 10 20 30 40 50 60 70 80
miles 10 0 10 20 30 40 50
Copies may be obtained from ERCB Information Services,
640 5 Avenue SW, Calgary, Alberta, Canada T2P 3G4

FIGURE 1

D.1 Paskapoo and Edmonton Interval

Reservoir Parameters:

Maximum Pay Thickness	19 metres
Porosity Range	18 to 31%
Pool Size Range	< 1 to 55 sections
Gas Saturation Range	50 to 75%
Recovery Factor Range	50 to 75%

Number of Play Areas = 2

Play Area 1: Edmonton — Continental Deposits — Central Alberta
(e.g. Nevis Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	2	17	858	88	11 - 13
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	10	83	118	12	4 - 34
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-

Play Area 1 is defined by the predominance of Edmonton Formation reserves in an area that is backstepped from the subcrop. Reservoirs exist in multiple sandstones and the main trapping mechanism is stratigraphic pinchouts. The relatively shallow depth of the Edmonton Formation results in a significant portion of the zone falling behind surface casing. The formation is also mostly fresh water saturated through direct communication with meteroic waters. Specialized logging techniques may be required to explore for gas in this zone.

The undiscovered potential for this play area is estimated at 1.23×10^9 m^3 (44 Bcf), with estimates of the undiscovered pool size ranging up to eight sections.

Play Area 2: Paskapoo – Edmonton – Continental and Fluvial Deposits – West-Central Alberta

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	-	-	-	-	-
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	25	100	748	100	1 - 128
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-

Play Area 2 is defined primarily by reservoir quality sandstones in the Paskapoo Formation. The northern limit of the gas potential is based on the proximity to the outcrop edge and the presence of freshwater sandstones. Since this area contains both formations, reservoirs can exist in more than a single sandstone and the pools are found in stratigraphic pinchouts of both continental Edmonton and fluvial Paskapoo deposits.

The relatively shallow depth of the Paskapoo Formation results in a major portion of the formation falling behind surface casing. Therefore, it is difficult to get an accurate estimation of undiscovered gas.

The undiscovered potential for this play area is estimated at 2.87×10^9 m^3 (102 Bcf), with estimates of the undiscovered pool size ranging up to four sections.

Ultimate Gas In Place

Paskapoo and Edmonton Interval	Initial Gas In Place	Undiscovered 10^9 m^3				Ultimate Gas In Place
	10^9 m^3	GRC 1	GRC 2	GRC 3	Total	10^9 m^3
Play Area:						
1. Edmonton – Continental Deposits – Central Alberta (e.g. Nevis Field)	0.98	0.57	0.12	0.54	1.23	2.21
2. Paskapoo – Edmonton – Continental and Fluvial Deposits – West-Central Alberta	0.75	1.76	0.25	0.86	2.87	3.62
Play Area Totals	1.73	2.33	0.37	1.40	4.10	5.83

BELLY RIVER
INTERVAL

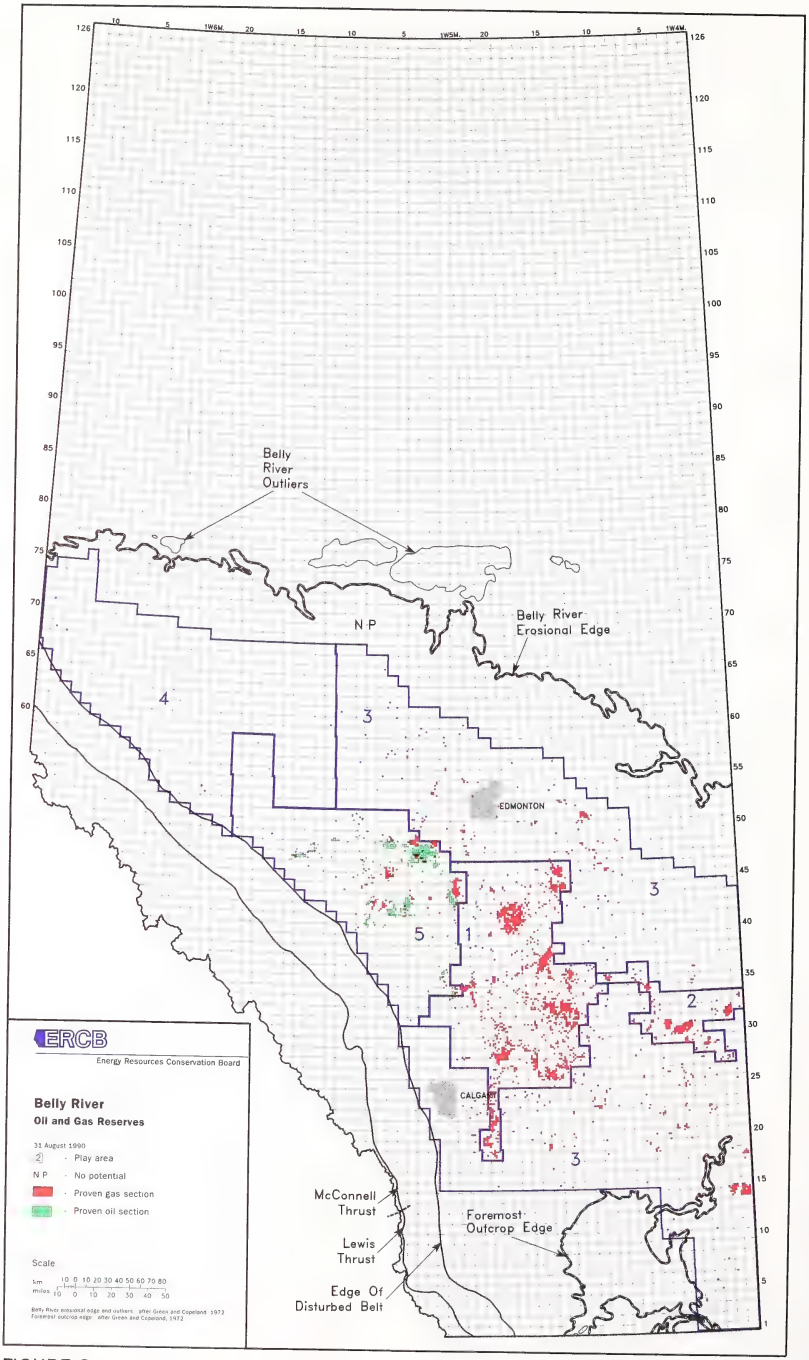

Belly River Outliers
N.P
Belly River Erosional Edge
EDMONTON
CALGARY
McConnell Thrust
Lewis Thrust
Edge Of Disturbed Belt
Foremost Outcrop Edge
ERCB
Energy Resources Conservation Board
Belly River
Oil and Gas Reserves
31 August 1990
Play area
N.P · No potential
Proven gas section
Proven oil section
Scale

FIGURE 2

D.2 Belly River Interval

Reservoir Parameters:

Maximum Pay Thickness	16 metres
Porosity Range	6 to 39%
Pool Size Range	< 1 to 95 sections
Gas Saturation Range	30 to 85%
Recovery Factor Range	12 to 94%

Constraints:

The nature of the Belly River does not readily lend it to exact log evaluation. The sandstones are often shaly and typically fresh water bearing and log analysis alone cannot provide definitive indications of potential. Also, the Belly River can contain several distinct sandstones, any of which may or may not be hydrocarbon bearing.

Method:

A statistical method was used to determine the potential for the Belly River in order to account for the possibility of encountering more than one pay zone in the wellbore. This method involved four steps:

(1) Determine the total number of potential sections.
(2) Distribute these potential sections among the three GRCs.
(3) Distribute each GRCs potential sections among the three gas types.
(4) Multiply potential sections by an average GIP per section value.

To determine the potential sections, the number of undrilled sections within each play area was multiplied by two factors. First, a "pay zones per well" ratio was defined as the historical average number of Belly River zones with proven reserves for each proven section drilled. Second, a success rate was calculated which is the proven sections divided by the number of total sections drilled. This success rate may be subjectively modified in order to constrain the anticipated pool size based on the contiguous undrilled area available. It is assumed that the "pay zones per well" ratio will remain constant throughout the life of the play. The combined multiplier for these two factors is shown in Appendix E, Table E.1 under GRC 3. After the total number of successful sections was calculated, it was then proportioned into the three gas resource categories.

All clastic formations for the entire stratigraphic column were reviewed to see their relative proportions in the three GRCs. These proportions were 16, 8 and 76% for GRCs 1, 2 and 3 respectively. These values were then used to calculate the number of sections assigned to the three gas resource categories of the Belly River. Sections that had been evaluated with possible pay were included in GRC 1 discounted at the appropriate historical success rate reflecting the type of drilling expected (see Appendix E, Table E.1 under GRC 1).

The potential sections in the three gas resource categories had to be proportioned into associated, non-associated and solution gas types. It is assumed that the hydrocarbon distribution ratios will remain unchanged in the future.

Finally, the potential sections for each gas type are multiplied by the average GIP per section to determine the undiscovered volumes.

Number of Play Areas = 5

Play Area 1: Delta Deposits – Central Alberta
(e.g. Bashaw Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	75	10	24 539	47	3 - 145
	Assoc.	1	<1	2 026	4	56
	Sol'n	1	<1	532	1	8
Two or less	Non-Assoc.	666	89	26 543	48	1 - 555
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-

Play Area 1 consists mainly of large, multi-section pools within deltaic deposits of the Belly River Formation. The reservoir is most often developed in the basal sandstones, however, almost the entire Belly River section has been found to contain gas-bearing sandstones. It should be noted that the fluvial Belly River sandstones are often not continuous over large areas as are the deltaic Basal Belly River sandstones. Pools are controlled by stratigraphic pinchouts of the fluvial or deltaic sandstones. Additional gas is expected from both pool expansion and new pools.

The undiscovered potential for this play area is estimated at 25.76×10^9 m^3 (914 Bcf), with estimates of the undiscovered pool size ranging up to five sections.

Play Area 2: Fluvial and Delta Deposits – East-Central Alberta
(e.g. Provost Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	18	21	5 421	81	6 - 52
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	67	79	1 249	19	1 - 69
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-

Play Area 2 covers an area where there is a transition from the fluvial/deltaic facies to a more marine influenced environment. Meandering and braided streams brought sediments to estuarine, channel dominated shorelines. The resulting reservoir quality of the sandstones in this area is poorer than in Play Area 1, due to the influence of nearshore muds. The play area is currently characterized by large multi-section pools with generally sporadic drilling density.

The undiscovered potential for this play area is estimated at 2.91×10^9 m^3 (103 Bcf), with estimates of the undiscovered pool size ranging up to four sections.

Play Area 3: Fluvial Deposits – North-Central and Southern Alberta
(e.g. Bantry Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	10	3	1 728	14	5 - 66
	Assoc.	-	-	-	-	-
	Sol'n	1	<1	16	<1	2
Two or less	Non-Assoc.	324	96	11 193	85	1 - 299
	Assoc.	1	<1	3	<1	3
	Sol'n	-	-	-	-	-

The northern limit of the Belly River gas potential is based on proximity to the outcrop edge. North of this limit, the sandstones are generally fresh water saturated through direct communication with

meteoric waters. The relatively shallow depth of the Belly River Formation results in a major portion falling behind surface casing.

The Foremost Formation outcrop of southern Alberta provides substantial water recharge into Belly River and equivalent sandstones. Therefore, most of the area adjacent to the outcrop is assigned no potential. This is confirmed by the absence of proven or potential pay in an area of significantly high drilling density.

This play is generally dominated by a strong marine overprint. The eastern and northern areas are dominated by an increase in the shale volume resulting in smaller pools that have reduced initial GIP values. The overall reserves distribution is concentrated in single or two section pools with the average IGIP value being much poorer than in Play Areas 1 and 5.

The undiscovered potential for this play area is estimated at 13.04 $\times$ 10^9 m^3 (463 Bcf), with estimates of the undiscovered pool size ranging up to six sections.

Play Area 4: Wapiti — Channel Deposits — Deep Basin

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	-	-	-	-	-
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	7	100	1 000	100	33 - 338
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-

Play Area 4 is characterized by Wapiti channel sandstones (Belly River equivalent). The high drilling density is a result of drilling for deeper targets. As in Play Area 3, the influence of meteoric water makes the log interpretation of gas reserves difficult without a valid flow test. The limited reserves reflect these two factors and therefore bypassed pay is expected to account for most of the potential.

The undiscovered potential for this play area is estimated at 3.55 $\times$ 10^9 m^3 (126 Bcf), with estimates of the undiscovered pool size ranging up to three sections.

Play Area 5: Delta and Channel Deposits – West-Central Alberta
(e.g. Peco Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	6	3	2 549	11	16 - 112
	Assoc.	6	3	1 918	8	17 - 135
	Sol'n	23	12	8 165	38	5 - 75
Two or less	Non-Assoc.	100	53	7 655	34	11 - 372
	Assoc.	10	5	875	4	5 - 232
	Sol'n	43	23	1 118	5	5 - 271

The western limit of this play area is defined by the eastern edge of the Disturbed Belt. Faulting in the western portion of the play area may have resulted in hydrocarbons migrating out of the Belly River interval. Oil pools in the central and eastern area are under saturated, i.e. typically there are no gas caps. Reserves have resulted in part from exploration for deeper targets. Recent drilling has concentrated on bypassed zones above the Pembina Cardium Pool and for channel sandstones in the Peco Field.

The undiscovered potential for this play area is estimated at 19.20×10^9 m^3 (682 Bcf), with estimates of the undiscovered pool size ranging up to four sections.

Ultimate Gas In Place

Belly River Interval	Initial Gas In Place	Undiscovered 10^9 m^3				Ultimate Gas In Place
	10^9 m^3	GRC 1	GRC 2	GRC 3	Total	10^9 m^3
Play Area:						
1. Delta Deposits – Central Alberta (e.g. Bashaw Field)	53.64	11.45	1.38	12.93	25.76	79.40
2. Fluvial and Delta Deposits – East-Central Alberta (e.g. Provost Field)	6.67	1.00	0.19	1.72	2.92	9.58
3. Fluvial Deposits – North-Central and Southern Alberta (e.g. Bantry Field)	12.94	4.88	0.81	7.35	13.04	25.98
4. Wapiti – Channel Deposits – Deep Basin	1.00	1.44	0.22	1.89	3.55	4.55
5. Delta and Channel Deposits – West-Central Alberta (e.g. Peco Field)	22.28	14.11	0.87	4.22	19.20	41.48
Play Area Totals	96.53	32.88	3.47	28.11	64.46	160.99

CHINOOK AND MILK RIVER INTERVAL

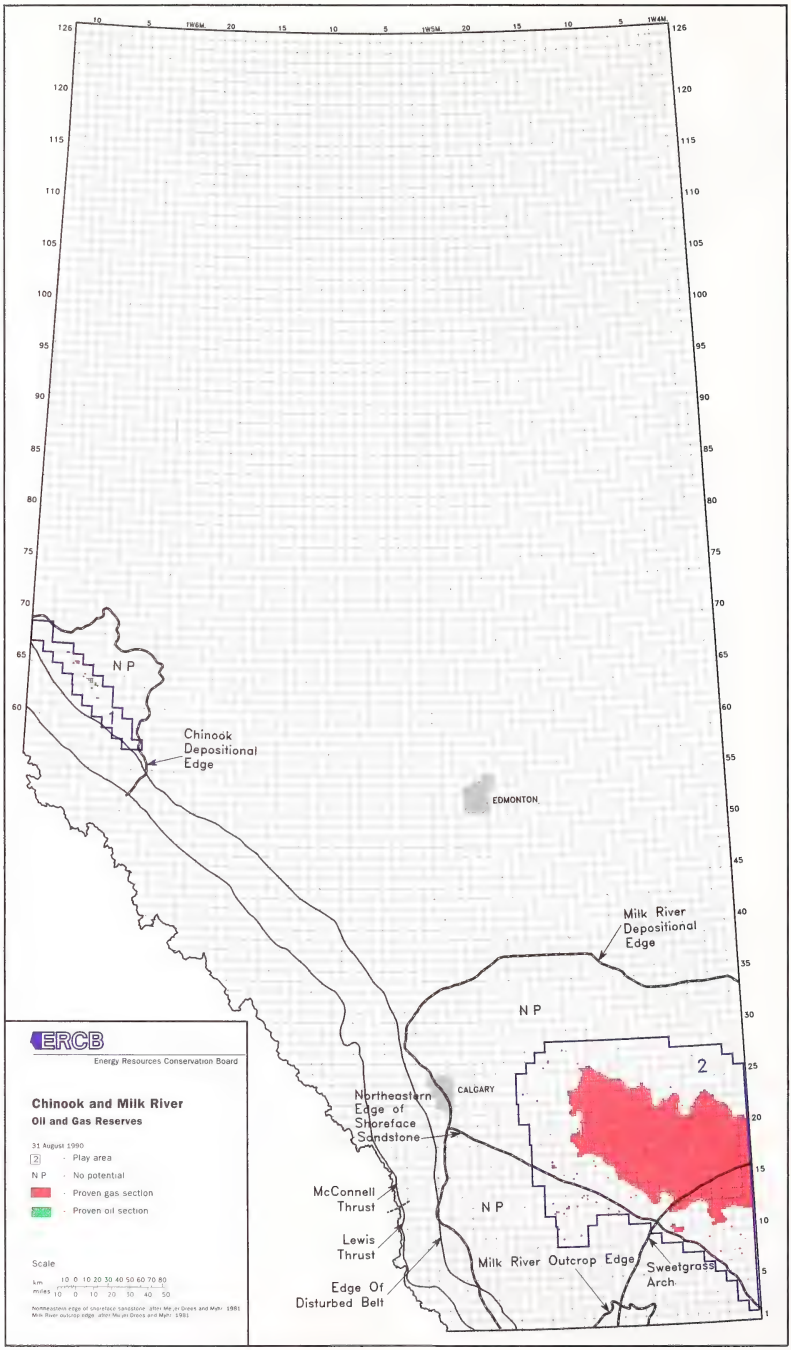

ERCB
Energy Resources Conservation Board
Chinook and Milk River
Oil and Gas Reserves
31 August 1990
2 · Play area
N P · No potential
· Proven gas section
· Proven oil section
Scale
km 10 0 10 20 30 40 50 60 70 80
miles 10 0 10 20 30 40 50
Northeastern edge of shoreface sandstone after Meijer Drees and Myhr, 1981
Milk River outcrop edge after Meijer Drees and Myhr, 1981
N P
Chinook Depositional Edge
EDMONTON
Milk River Depositional Edge
N P
2
CALGARY
Northeastern Edge of Shoreface Sandstone
McConnell Thrust
N P
Lewis Thrust
Edge Of Disturbed Belt
Milk River Outcrop Edge
Sweetgrass Arch

FIGURE 3

D.3 Chinook and Milk River Interval

Reservoir Parameters:

Chinook

Maximum Pay Thickness	7 metres
Porosity Range	10 to 22%
Pool Size Range	< 1 to 5 sections
Gas Saturation Range	55 to 85%
Recovery Factor Range	70 to 85%

Milk River

Maximum Pay Thickness	10 metres
Porosity Range	15 to 30%
Pool Size Range	< 1 to 1471 sections (41 TWPs)
Gas Saturation Range	40 to 70%
Recovery Factor Range	50 to 80%

Number of Play Areas = 2

Play Area 1: Chinook – Bar Deposits – Northwestern Alberta
(e.g. Red Rock Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	1	14	258	27	51
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	6	86	706	73	43 - 208
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-

The play area boundary is based on the limits of Chinook sandstone development. The trapping mechanism is primarily stratigraphic as marine bar sandstones grade laterally into offshore siltstone and shale. The Chinook thins appreciably in an eastward direction. Potential exists for both pool expansion and new pools.

The undiscovered potential for this play area is estimated at 4.81×10^9 m^3 (171 Bcf), with estimates of the undiscovered pool size ranging up to four sections.

Play Area 2: Milk River – Shelf Deposits – Southeastern Alberta
(e.g. Medicine Hat Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	25	74	166 091	>99	6 - 68
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	9	26	218	<1	4 - 51
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-

The southern boundary of this play area is the updip water saturated beach sandstones of the Milk River Formation which form a trap similar to that found in the Deep Basin (Masters 1979). The northern and western boundaries of this play are based on a shale volume of approximately 50%, which appears to coincide with the current limit of technologically recoverable gas. Future reserves will be added predominantly by development drilling adjacent to the main Milk River pool boundary and through advancements in technology.

The undiscovered potential for this play area is estimated at 57.98 $\times$ 10^9 m^3 (2058 Bcf).

Ultimate Gas In Place

Chinook and Milk River Interval	Initial Gas In Place	Undiscovered 10^9 m^3				Ultimate Gas In Place
	10^9 m^3	GRC 1	GRC 2	GRC 3	Total	10^9 m^3
Play Area:						
1. Chinook – Bar Deposits – Northwestern Alberta (e.g. Red Rock Field)	0.96	1.04	0.48	3.29	4.81	5.77
2. Milk River – Shelf Deposits – Southeastern Alberta (e.g. Medicine Hat Field)	166.31	42.48	14.17	1.33	57.98	224.29
Play Area Totals	167.27	43.52	14.65	4.62	62.79	230.06

MEDICINE HAT
INTERVAL

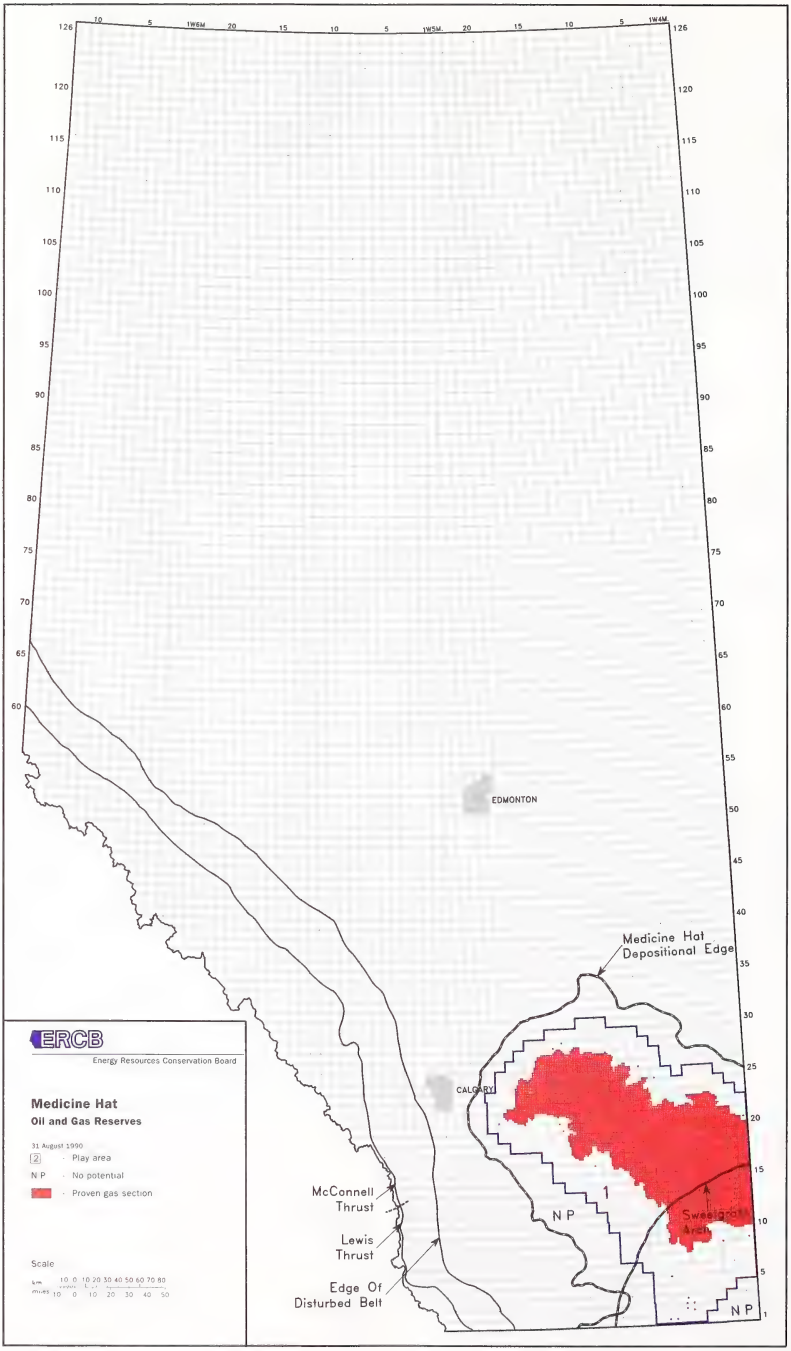

ERCB
Energy Resources Conservation Board
Medicine Hat
Oil and Gas Reserves
31 August 1990
2 · Play area
N·P · No potential
· Proven gas section
Scale
km 10 0 10 20 30 40 50 60 70 80
miles 10 0 10 20 30 40 50
EDMONTON
CALGARY
Medicine Hat
Depositional Edge
McConnell
Thrust
Lewis
Thrust
Edge Of
Disturbed Belt
N P
1
Sweetgrass
Area
N P

FIGURE 4

D.4 Medicine Hat Interval

Reservoir Parameters:

Maximum Pay Thickness	4 metres
Porosity Range	14 to 30%
Pool Size Range	< 1 to 2106 sections (59 TWPs)
Gas Saturation Range	45 to 65%
Recovery Factor Range	50 to 80%

Number of Play Areas = 1

Play Area 1: Shelf Deposits – Southeastern Alberta
(e.g. Medicine Hat Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	63	89	194 463	> 99	1 - 37
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	8	11	87	< 1	4 - 19
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-

Play Area 1 consists primarily of shallow marine sheet sandstones and interbedded shales. The boundary for this play area is based on a shale volume of approximately 50%, which appears to coincide with the current limit of technologically recoverable gas.

Future reserves will be added predominantly by development drilling adjacent to the main Medicine Hat pool boundaries and through advancements in exploitation technology.

The undiscovered potential for this play area is estimated at 58.90×10^9 m^3 (2091 Bcf).

Ultimate Gas In Place

Medicine Hat Interval	Initial Gas In Place	Undiscovered 10^9 m^3				Ultimate Gas In Place
	10^9 m^3	GRC 1	GRC 2	GRC 3	Total	10^9 m^3
Play Area: 1. Shelf Deposits – Southeastern Alberta (e.g. Medicine Hat Field)	194.55	44.67	13.75	0.48	58.90	253.45
Play Area Totals	194.55	44.67	13.75	0.48	58.90	253.45

CARDIUM
INTERVAL

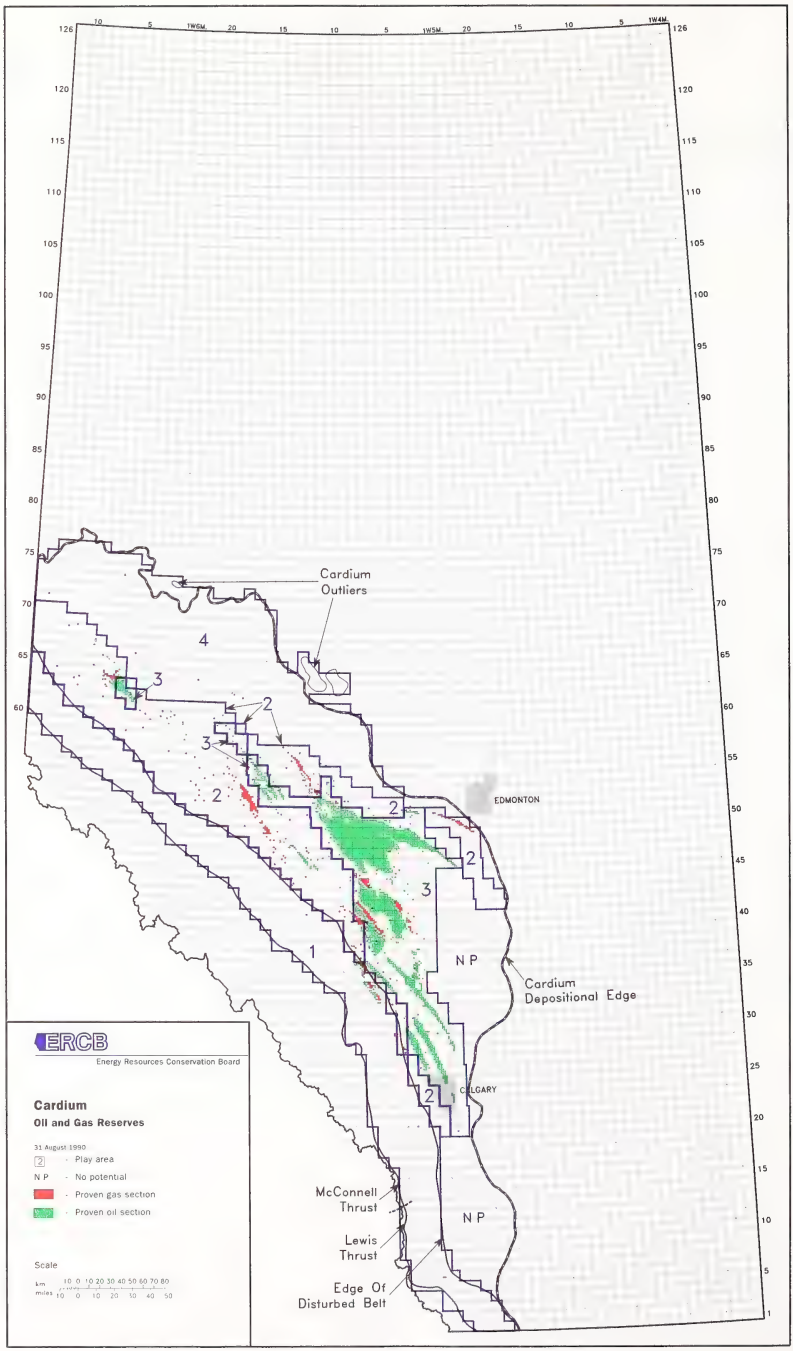

Cardium
Outliers
4
3
2
3
2
2
2
3
1
N P
Cardium
Depositional Edge
EDMONTON
CALGARY
2
McConnell
Thrust
N P
Lewis
Thrust
Edge Of
Disturbed Belt
ERCB
Energy Resources Conservation Board
Cardium
Oil and Gas Reserves
31 August 1990
2 - Play area
N P - No potential
- Proven gas section
- Proven oil section
Scale
km
miles

FIGURE 5

D.5 Cardium Interval

Reservoir Parameters:

Maximum Pay Thickness	19 metres
Porosity Range	4 to 30%
Pool Size Range	< 1 to 740 sections (21 TWPs)
Gas Saturation Range	65 to 95%
Recovery Factor Range	14 to 90%

Number of Play Areas = 4

Play Area 1: Foothills
(e.g. Ricinus Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	2	3	1 566	8	121 - 160
	Assoc.	3	5	7 577	39	356 - 639
	Sol'n	4	6	3 742	19	21 - 115
Two or less	Non-Assoc.	13	21	2 146	11	31 - 649
	Assoc.	4	6	675	3	17 - 273
	Sol'n	37	59	3 884	20	8 - 423

Play Area 1 is defined by the edge of the Disturbed Belt in the east and the McConnell and Lewis Thrusts to the west. Cardium reservoirs are confined to clastic deposits within scour channels that trend northwest-southeast. The Cardium is not present over much of the play because of non-deposition, uplift and erosion as well as a lack of structural closure. Consequently, most of the play was considered to have no potential. However, the Cardium is thrust into structures with potential for multiple repeats of the reservoir units similar to those found in Ricinus and Ricinus West. New pools of this type could contribute significant incremental volumes.

The undiscovered potential for this play area is estimated at 94.20×10^9 m^3 (3344 Bcf), with estimates of the undiscovered pool size ranging up to nine sections.

Play Area 2: Gas Prone — Bar Deposits — West-Central Alberta
(e.g. Ansell Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	7	5	18 265	45	19 - 311
	Assoc.	3	2	2 426	6	26 - 86
	Sol'n	7	5	3 236	8	1 - 38
Two or less	Non-Assoc.	111	78	16 298	40	8 - 664
	Assoc.	4	2	128	<1	6 - 58
	Sol'n	11	8	287	<1	5 - 77

Play Area 2 is characterized by gas-prone pools in northwest-southeast trending bar sandstones. The play area is limited to the east by the occurrence of Cardium oil pools and to the west by the edge of the Disturbed Belt. Reservoirs can exist in more than a single sandstone and most pools are found in stratigraphic traps. The reservoirs can be fault controlled and often contain wet gases. Both reservoir expansion and discovery of new pools is expected to provide additional gas.

The undiscovered potential for this play area is estimated at 129.86 $\times$ 10^9 m^3 (4610 Bcf), with estimates of the undiscovered pool size ranging up to 12 sections.

Play Area 3: Oil Prone — Bar and Shelf Deposits — Central Alberta
(e.g. Pembina Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	2	2	824	<1	48 - 71
	Assoc.	8	8	17 055	9	30 - 301
	Sol'n	32	34	175 555	89	1 - 171
Two or less	Non-Assoc.	21	22	2 091	1	7 - 282
	Assoc.	11	11	716	<1	2 - 360
	Sol'n	22	23	529	<1	3 - 130

Play Area 3 is characterized by oil-prone Cardium pools in northwest-southeast trending bar sandstones and large marine sheet sandstones. Reservoirs within the Cardium interval are often

contained within stratigraphic traps in the Raven River Member. Potential is expected in the form of solution gas and was assigned to the expansion of existing pools and the discovery of new pools.

The undiscovered potential for this play area is estimated at 28.02×10^9 m^3 (995 Bcf), with estimates of the undiscovered pool size ranging up to seven sections.

Play Area 4: Water Prone – Bar Deposits – North-Central Alberta
(e.g. Waskahigan Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	-	-	-	-	-
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	6	86	289	98	19 - 125
	Assoc.	-	-	-	-	-
	Sol'n	1	14	6	2	6

Play Area 4 is characterized by water-prone Cardium in northwest-southeast trending bar sandstones. The play area is limited by the subcrop to the north and the downdip oil and gas-prone areas to the south and west. Fresh water has recharged much of the section, due to the proximity of the subcrop to the north, resulting in poor discovery of reserves in this play area. However, as fresh water creates problems in petrophysical analysis, there may be some bypassed hydrocarbon pay in the Cardium. It is this bypassed pay that accounts for most of the potential assigned to GRC 3. In GRC 1, wells with possible reserves contribute to the bulk of its undiscovered volume.

The undiscovered potential for this play area is estimated at 1.27×10^9 m^3 (45 Bcf), with estimates of the undiscovered pool size ranging up to three sections.

Play Area 2: Gas Prone – Bar Deposits – West-Central Alberta
(e.g. Ansell Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	7	5	18 265	45	19 - 311
	Assoc.	3	2	2 426	6	26 - 86
	Sol'n	7	5	3 236	8	1 - 38
Two or less	Non-Assoc.	111	78	16 298	40	8 - 664
	Assoc.	4	2	128	<1	6 - 58
	Sol'n	11	8	287	<1	5 - 77

Play Area 2 is characterized by gas-prone pools in northwest-southeast trending bar sandstones. The play area is limited to the east by the occurrence of Cardium oil pools and to the west by the edge of the Disturbed Belt. Reservoirs can exist in more than a single sandstone and most pools are found in stratigraphic traps. The reservoirs can be fault controlled and often contain wet gases. Both reservoir expansion and discovery of new pools is expected to provide additional gas.

The undiscovered potential for this play area is estimated at 129.86 $\times$ 10^9 m^3 (4610 Bcf), with estimates of the undiscovered pool size ranging up to 12 sections.

Play Area 3: Oil Prone – Bar and Shelf Deposits – Central Alberta
(e.g. Pembina Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	2	2	824	<1	48 - 71
	Assoc.	8	8	17 055	9	30 - 301
	Sol'n	32	34	175 555	89	1 - 171
Two or less	Non-Assoc.	21	22	2 091	1	7 - 282
	Assoc.	11	11	716	<1	2 - 360
	Sol'n	22	23	529	<1	3 - 130

Play Area 3 is characterized by oil-prone Cardium pools in northwest-southeast trending bar sandstones and large marine sheet sandstones. Reservoirs within the Cardium interval are often

contained within stratigraphic traps in the Raven River Member. Potential is expected in the form of solution gas and was assigned to the expansion of existing pools and the discovery of new pools.

The undiscovered potential for this play area is estimated at 28.02 $\times$ 10^9 m^3 (995 Bcf), with estimates of the undiscovered pool size ranging up to seven sections.

Play Area 4: Water Prone — Bar Deposits — North-Central Alberta
(e.g. Waskahigan Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	-	-	-	-	-
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	6	86	289	98	19 - 125
	Assoc.	-	-	-	-	-
	Sol'n	1	14	6	2	6

Play Area 4 is characterized by water-prone Cardium in northwest-southeast trending bar sandstones. The play area is limited by the subcrop to the north and the downdip oil and gas-prone areas to the south and west. Fresh water has recharged much of the section, due to the proximity of the subcrop to the north, resulting in poor discovery of reserves in this play area. However, as fresh water creates problems in petrophysical analysis, there may be some bypassed hydrocarbon pay in the Cardium. It is this bypassed pay that accounts for most of the potential assigned to GRC 3. In GRC 1, wells with possible reserves contribute to the bulk of its undiscovered volume.

The undiscovered potential for this play area is estimated at 1.27 $\times$ 10^9 m^3 (45 Bcf), with estimates of the undiscovered pool size ranging up to three sections.

Ultimate Gas In Place

Cardium Interval	Initial Gas In Place	Undiscovered 10^9 m^3				Ultimate Gas In Place
	10^9 m^3	GRC 1	GRC 2	GRC 3	Total	10^9 m^3
Play Area:						
1. Foothills (e.g. Ricinus Field)	19.59	5.02	5.02	84.16	94.20	113.79
2. Gas Prone – Bar Deposits – West-Central Alberta (e.g. Ansell Field)	40.64	58.33	9.77	61.76	129.86	170.50
3. Oil Prone – Bar and Shelf Deposits – Central Alberta (e.g. Pembina Field)	196.77	16.27	0.11	11.64	28.02	224.79
4. Water Prone – Bar Deposits – North-Central Alberta (e.g. Waskahigan Field)	0.30	0.67	0.00	0.60	1.27	1.57
Play Area Totals	257.30	80.29	14.90	158.16	253.35	510.65

DOE CREEK
INTERVAL

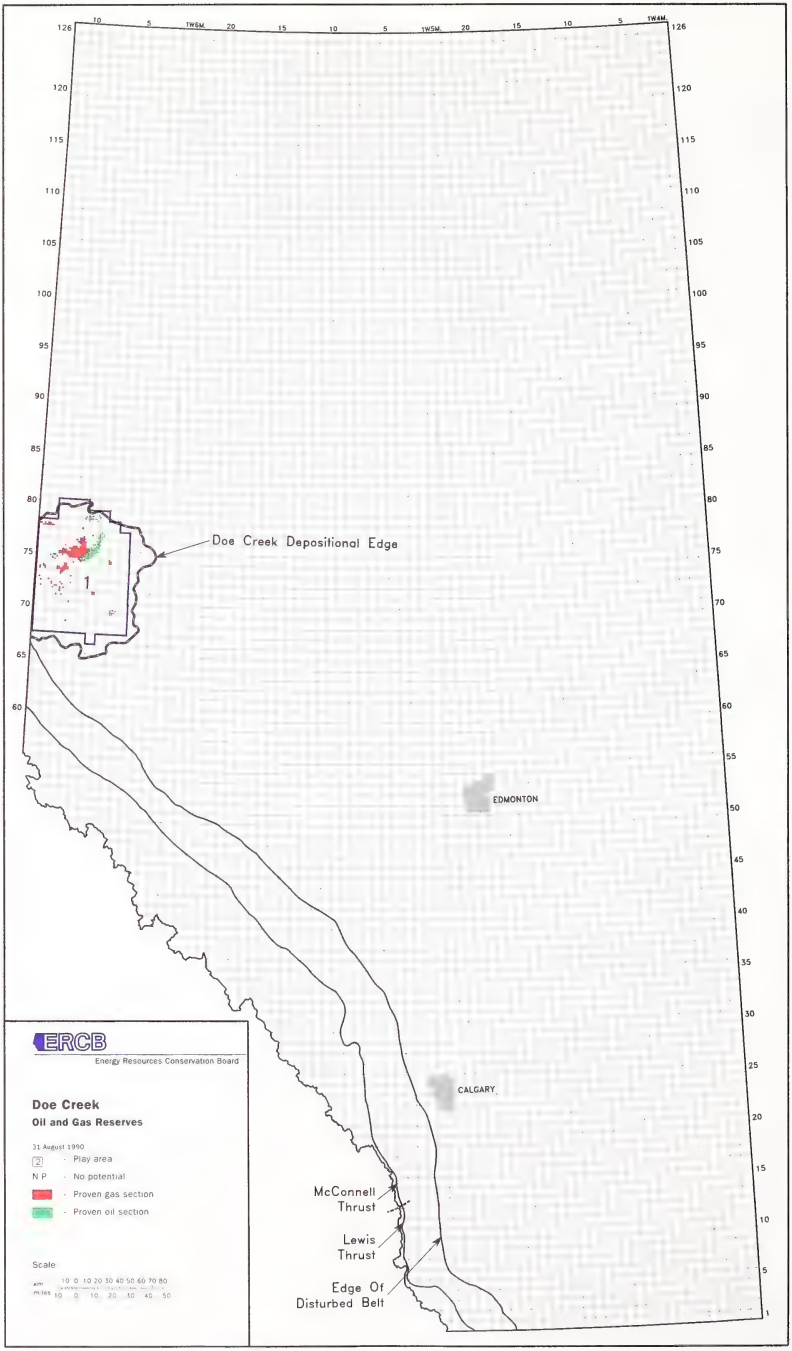

Doe Creek Depositional Edge
1
EDMONTON
CALGARY
McConnell Thrust
Lewis Thrust
Edge Of Disturbed Belt
ERCB
Energy Resources Conservation Board
Doe Creek
Oil and Gas Reserves
31 August 1990
2 · Play area
N P · No potential
· Proven gas section
· Proven oil section
Scale
km 10 0 10 20 30 40 50 60 70 80
miles 10 0 10 20 30 40 50

FIGURE 6

D.6 Doe Creek Interval

Reservoir Parameters:

Maximum Pay Thickness	5 metres
Porosity Range	9 to 28%
Pool Size Range	<1 to 35 sections
Gas Saturation Range	35 to 80%
Recovery Factor Range	50 to 80%

Number of Play Areas = 1

Play Area 1: Bar and Shelf Deposits – Peace River Arch
(e.g. Valhalla Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	8	15	5 714	70	9 - 48
	Assoc.	1	2	63	1	15
	Sol'n	1	2	594	7	11
Two or less	Non-Assoc.	34	64	1 430	18	3 - 430
	Assoc.	8	15	240	3	3 - 84
	Sol'n	1	2	31	<1	31

Play Area 1 is characterized by shallow marine sheet sandstones and northeast-southwest trending bar sandstones. The play area is limited as the sandstones grade laterally into marine shales. More than one sandstone has proven productive, therefore, multiple pay zones may be encountered when drilling for this target. Additional gas is expected primarily from pool expansion.

The undiscovered potential for this play area is estimated at 7.25×10^9 m^3 (257 Bcf), with estimates of the undiscovered pool size ranging up to four sections.

Ultimate Gas In Place

Doe Creek Interval	Initial Gas In Place	Undiscovered 10^9 m^3				Ultimate Gas In Place
	10^9 m^3	GRC 1	GRC 2	GRC 3	Total	10^9 m^3
Play Area: 1. Bar and Shelf Deposits – Peace River Arch (e.g. Valhalla Field)	8.07	3.98	1.35	1.92	7.25	15.32
Play Area Totals	8.07	3.98	1.35	1.92	7.25	15.32

DUNVEGAN
INTERVAL

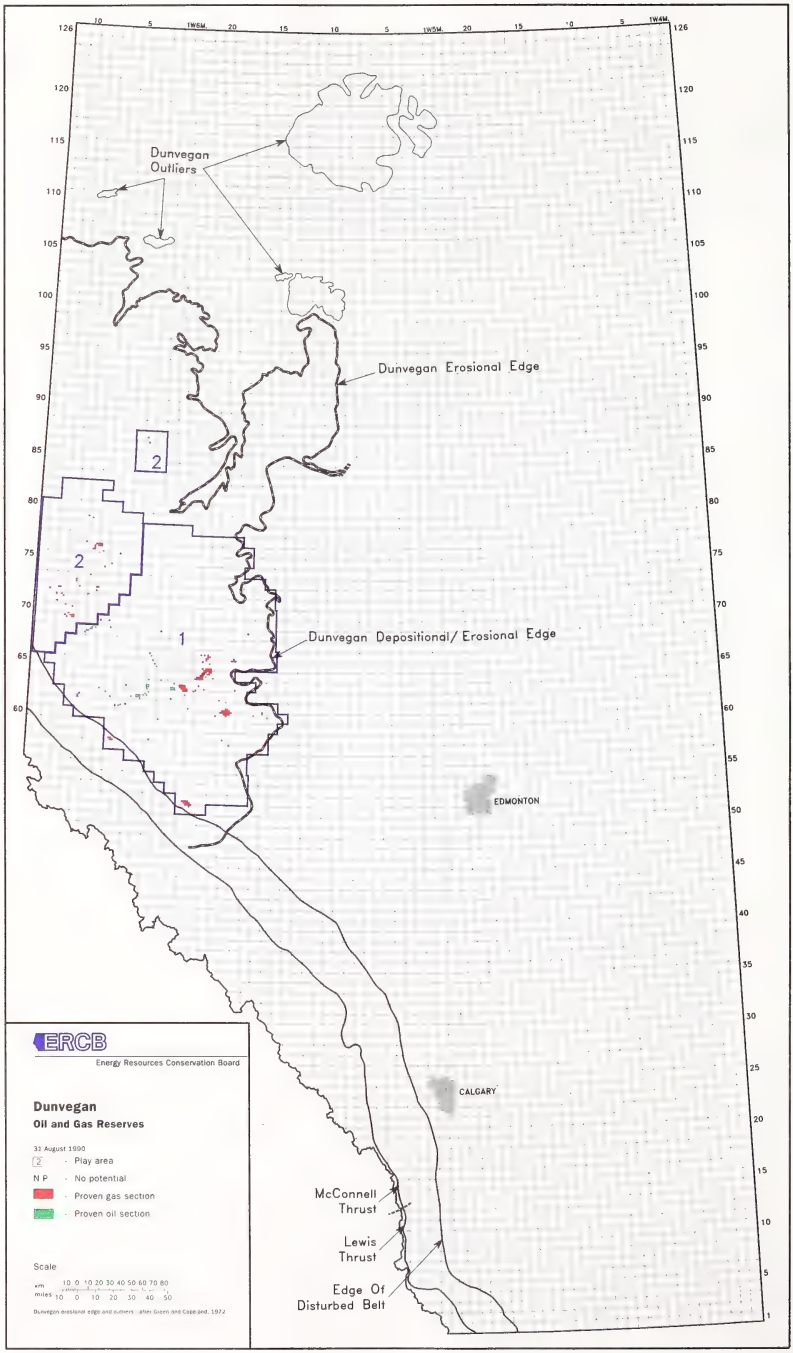

Dunvegan Outliers
Dunvegan Erosional Edge
Dunvegan Depositional/ Erosional Edge
EDMONTON
CALGARY
McConnell Thrust
Lewis Thrust
Edge Of Disturbed Belt
ERCB
Energy Resources Conservation Board
Dunvegan
Oil and Gas Reserves
31 August 1990
2 · Play area
N P · No potential
Proven gas section
Proven oil section
Scale
km 10 0 10 20 30 40 50 60 70 80
miles 10 0 10 20 30 40 50
Dunvegan erosional edge and outliers - after Green and Cope and, 1972

FIGURE 7

D.7 Dunvegan Interval

Reservoir Parameters:

Maximum Pay Thickness	13 metres
Porosity Range	7 to 33%
Pool Size Range	< 1 to 19 sections
Gas Saturation Range	30 to 85%
Recovery Factor Range	50 to 90%

Number of Play Areas = 2

Play Area 1: Shallow Bar and Shelf Deposits – Northwestern Alberta
(e.g. Waskahigan Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	7	16	7 541	47	39 - 227
	Assoc.	3	7	3 859	24	90 - 175
	Sol'n	3	7	559	4	14 - 22
Two or less	Non-Assoc.	27	60	3 856	24	18 - 633
	Assoc.	3	7	59	< 1	5 - 47
	Sol'n	2	4	112	1	46 - 66

Play Area 1 is characterized by the presence of shallow bar and sheet sandstones associated with an overall deltaic environment. The play area is limited by sandstones grading laterally into marine shales to the east. The stratigraphically trapped hydrocarbons are in pools that trend northeast-southwest. Additional gas is expected from both pool expansion and new pools.

The undiscovered potential for this play area is estimated at 24.93×10^9 m^3 (885 Bcf), with estimates of the undiscovered pool size ranging up to four sections.

Play Area 2: Delta and Channel Deposits — Northwestern Alberta
(e.g. Valhalla Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	3	11	411	20	16 - 43
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	25	89	1 686	80	10 - 265
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-

Play Area 2 consists of delta plain sandstones. The play area is limited to the south and east by the transition to marine sediments of Play Area 1 and to the north by the erosional edge of the Dunvegan Formation. Deltaic channel sequences oriented perpendicular to the marine bar sandstones of Play Area 1 are the primary reservoir. In addition, local discontinuities within various sandstones of the sequence create local stratigraphic traps.

Additional gas is expected from both pool expansion and new pools. The undiscovered potential for this play area is estimated at 7.96×10^9 m^3 (283 Bcf), with estimates of the undiscovered pool size ranging up to three sections.

Ultimate Gas In Place

Dunvegan Interval	Initial Gas In Place	Undiscovered 10^9 m^3				Ultimate Gas In Place
	10^9 m^3	GRC 1	GRC 2	GRC 3	Total	10^9 m^3
Play Area:						
1. Shallow Bar and Shelf Deposits — Northwestern Alberta (e.g. Waskahigan Field)	15.99	9.49	3.96	11.48	24.93	40.92
2. Delta and Channel Deposits — Northwestern Alberta (e.g. Valhalla Field)	2.10	3.72	1.26	2.98	7.96	10.06
Play Area Totals	18.09	13.21	5.22	14.46	32.89	50.98

SECOND WHITE SPECKS INTERVAL

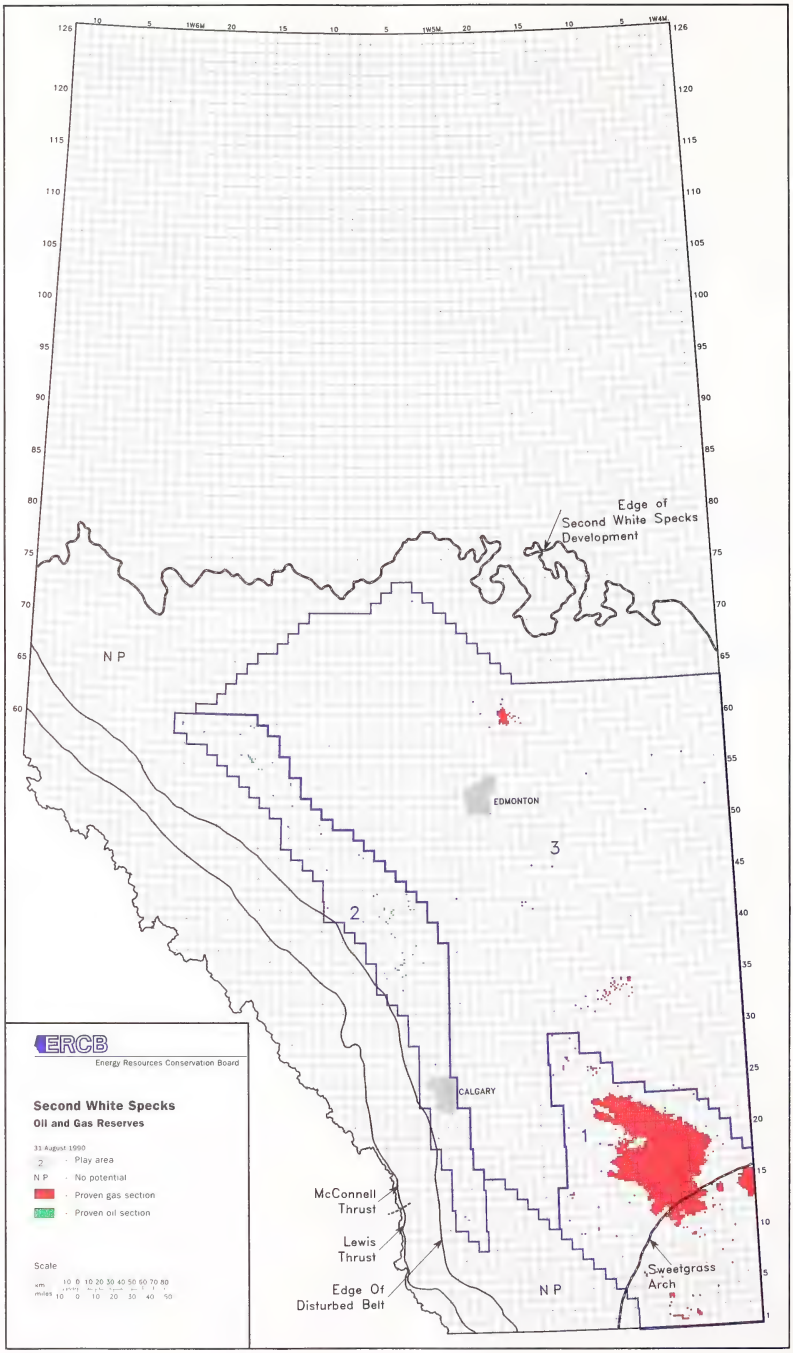

Edge of
Second White Specks
Development
N P
EDMONTON
3
2
1
CALGARY
McConnell
Thrust
Lewis
Thrust
Edge Of
Disturbed Belt
N P
Sweetgrass
Arch
ERCB
Energy Resources Conservation Board
Second White Specks
Oil and Gas Reserves
31 August 1990
2 · Play area
N P · No potential
· Proven gas section
· Proven oil section
Scale

FIGURE 8

D.8 Second White Specks Interval

Reservoir Parameters:

Maximum Pay Thickness	19 metres
Porosity Range	3 to 34%
Pool Size Range	< 1 to 706 sections (20 TWPs)
Gas Saturation Range	35 to 80%
Recovery Factor Range	50 to 85%

Number of Play Areas = 3

Play Area 1: Shelf Deposits — Southeastern Alberta
(e.g. Medicine Hat Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	24	32	62 514	98	6 - 29
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	52	68	996	2	1 - 130
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-

Play Area 1 is characterized by sediments deposited on a storm-dominated shelf. The play area is limited to the portion of the province proximal to the Sweetgrass Arch. Shoaling influenced by the topography on the arch resulted in the deposition of coarser and cleaner sands in this area. Future reserves are likely to be added predominantly by development drilling adjacent to the main Second White Specks pool boundaries.

The undiscovered potential for this play area is estimated at 48.59×10^9 m^3 (1725 Bcf).

Play Area 2: Oil Prone — Fractured Shales — Western Alberta
(e.g. Pine Creek Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	-	-	-	-	-
	Assoc.	-	-	-	-	-
	Sol'n	2	15	798	50	20 - 145
Two or less	Non-Assoc.	4	31	560	35	22 - 257
	Assoc.	-	-	-	-	-
	Sol'n	7	54	248	15	10 - 137

Play Area 2 is characterized by hydrocarbon-bearing fractured shales. The fractures have been reported as being caused by volume reduction due to expulsion of water from clays or from tectonic forces related to the development of the Cordillera. The play area is limited to the east by the approximate eastern most extension of oil reserves and to the west by the Disturbed Belt.

The minimal discovery of reserves to date in this area leads to limited confidence in estimating undiscovered gas in place. Therefore, potential is assigned primarily to GRC 3. In GRC 1, wells with possible reserves contribute to the bulk of its undiscovered volume. Additional gas is likely to be found in new pools when exploration techniques are developed to determine the location of fractured shales.

The undiscovered potential for this play area is estimated at 3.41×10^9 m^3 (121 Bcf), with estimates of the undiscovered pool size ranging up to three sections.

Play Area 3: Shelf Deposits – Central Alberta
(e.g. Garden Plains Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	2	5	598	47	9 - 26
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	40	95	661	53	3 - 50
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-

Play Area 3 consists of Second White Specks sandstone development not already defined by Play Areas 1 and 2. Gas reservoirs occur in sandier portions of marine shelf sediments. The minimal discovery of reserves to date in this area leads to limited confidence in estimating undiscovered gas in place. Therefore, potential is assigned primarily to GRC 3. In GRC 1, wells with possible reserves contribute to the bulk of its undiscovered volume. Additional gas is expected primarily from the discovery of new pools.

The undiscovered potential for this play area is estimated at 2.79×10^9 m^3 (99 Bcf), with estimates of the undiscovered pool size ranging up to four sections.

Ultimate Gas In Place

Second White Specks Interval	Initial Gas In Place	Undiscovered 10^9 m^3				Ultimate Gas In Place
	10^9 m^3	GRC 1	GRC 2	GRC 3	Total	10^9 m^3
Play Area:						
1. Shelf Deposits – Southeastern Alberta (e.g. Medicine Hat Field)	63.51	31.64	14.75	2.20	48.59	112.10
2. Oil Prone – Fractured Shales – Western Alberta (e.g. Pine Creek Field)	1.61	0.14	0.00	3.27	3.41	5.02
3. Shelf Deposits – Central Alberta (e.g. Garden Plains Field)	1.26	0.32	0.00	2.47	2.79	4.05
Play Area Totals	66.38	32.10	14.75	7.94	54.79	121.17

BASE OF FISH SCALES
INTERVAL

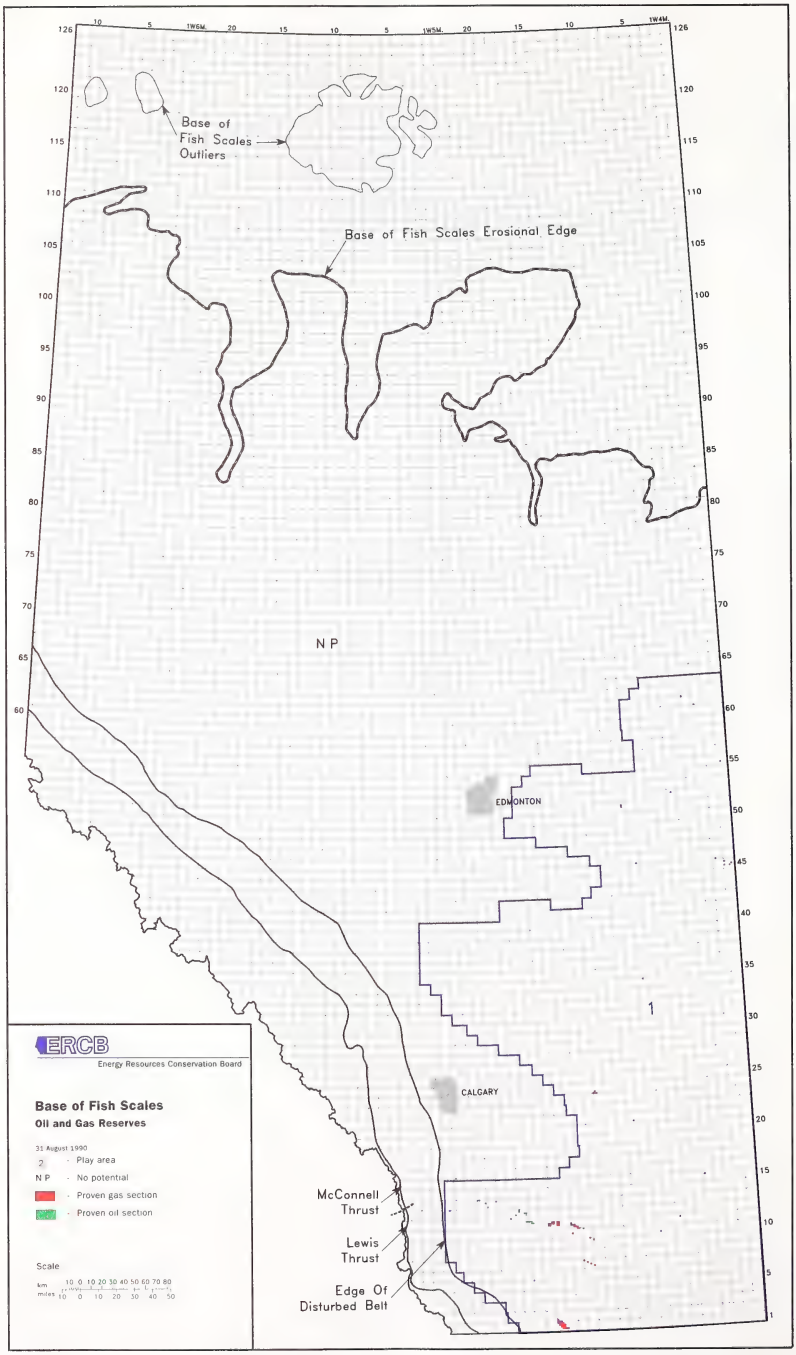

Base of Fish Scales Outliers
Base of Fish Scales Erosional Edge
N P
EDMONTON
CALGARY
1
McConnell Thrust
Lewis Thrust
Edge Of Disturbed Belt
ERCB
Energy Resources Conservation Board
Base of Fish Scales
Oil and Gas Reserves
31 August 1990
2 - Play area
N P - No potential
- Proven gas section
- Proven oil section
Scale
km 10 0 10 20 30 40 50 60 70 80
miles 10 0 10 20 30 40 50

FIGURE 9

D.9 Base of Fish Scales Interval

Reservoir Parameters:

Maximum Pay Thickness	10 metres
Porosity Range	9 to 30%
Pool Size Range	< 1 to 19 sections
Gas Saturation Range	35 to 70%
Recovery Factor Range	50 to 75%

Number of Play Areas = 1

Play Area 1: Shelf Deposits – Central and Southern Alberta
(e.g. Iron Springs Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	6	21	392	59	2 - 15
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	22	79	271	41	1 - 82
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-

Play Area 1 is characterized by clastic units which are predominantly marine in origin. The Barons Sand, found in the southern part of the play, is included in this interval. The limits of the play area are based on step-outs from proven and possible reserves, approximating their general northwest-southeast trend.

The minimal discovery of reserves to date in this interval leads to limited confidence in estimating undiscovered gas in place. Therefore, potential is assigned primarily to GRC 3. In GRC 1, wells with possible reserves contribute to the bulk of its undiscovered volume. Additional gas is expected primarily from the discovery of new pools.

The undiscovered potential for this play area is estimated at 1.28×10^9 m^3 (45 Bcf), with estimates of the undiscovered pool size ranging up to four sections.

Ultimate Gas In Place

Base of Fish Scales Interval	Initial Gas In Place	Undiscovered 10^9 m^3				Ultimate Gas In Place
	10^9 m^3	GRC 1	GRC 2	GRC 3	Total	10^9 m^3
Play Area: 1. Shelf Deposits – Central and Southern Alberta (e.g. Iron Springs Field)	0.83	0.13	0.00	1.15	1.28	2.11
Play Area Totals	0.83	0.13	0.00	1.15	1.28	2.11

VIKING
INTERVAL

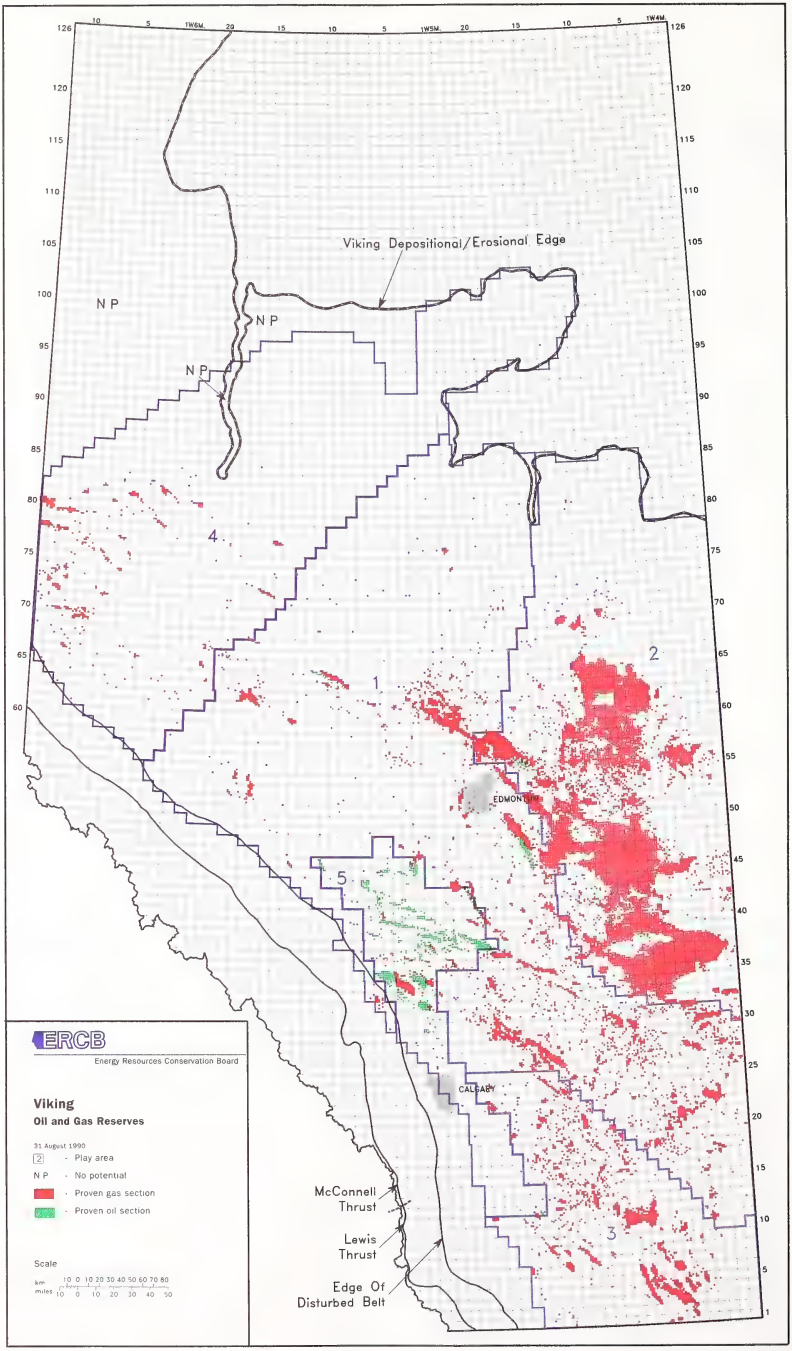

Viking Depositional/Erosional Edge
N P
N P
N P
4
1
2
5
3
EDMONTON
CALGARY
McConnell Thrust
Lewis Thrust
Edge Of Disturbed Belt
ERCB
Energy Resources Conservation Board
Viking
Oil and Gas Reserves
31 August 1990
2 · Play area
N P · No potential
· Proven gas section
· Proven oil section
Scale
km 10 0 10 20 30 40 50 60 70 80
miles 10 0 10 20 30 40 50

FIGURE 10

D.10 Viking Interval

Reservoir Parameters:

Maximum Pay Thickness	49 metres
Porosity Range	4 to 36%
Pool Size Range	< 1 to 1567 sections (44 TWPs)
Gas Saturation Range	20 to 90%
Recovery Factor Range	25 to 93%

Number of Play Areas = 5

Play Area 1: Viking Bar and Shelf Deposits – Central Alberta
(e.g. Joarcam Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	189	16	105 546	70	1 - 261
	Assoc.	6	1	6 321	4	9 - 67
	Sol'n	5	< 1	1 927	1	1 - 13
Two or less	Non-Assoc.	965	81	36 738	24	1 - 847
	Assoc.	16	1	442	< 1	1 - 53
	Sol'n	6	1	88	< 1	2 - 29

Play Area 1 consists primarily of bar sandstones with interbar sheet sandstone development. Bar sandstones are more common to the west while sheet sandstones become more common to the east. Additional gas is expected predominantly from new pools.

The undiscovered potential for this play area is estimated at 103.55×10^9 m^3 (3676 Bcf), with estimates of the undiscovered pool size ranging up to 12 sections.

Play Area 2: Viking – Shelf Deposits – East-Central Alberta
(e.g. Provost Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	146	15	98 861	59	< 1 - 111
	Assoc.	6	1	53 786	32	3 - 36
	Sol'n	7	1	2 718	1	3 - 12
Two or less	Non-Assoc.	810	83	11 848	7	< 1 - 172
	Assoc.	5	1	259	< 1	3 - 81
	Sol'n	6	1	63	< 1	2 - 37

Play Area 2 is characterized by extensive thin sheet sandstones. Some bar sandstones are present on the play's western edge. In general, reservoir quality deteriorates to the northeast due to increasing shale content. Additional gas is expected primarily from the development of existing pools.

The undiscovered potential for this play area is estimated at 22.39×10^9 m^3 (795 Bcf), with estimates of the undiscovered pool size ranging up to five sections.

Play Area 3: Bow Island – Bar Deposits – Southern Alberta
(e.g. Pendant d'Oreille Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	99	15	32 776	64	1 - 172
	Assoc.	2	< 1	139	< 1	8 - 33
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	549	84	17 903	35	1 - 600
	Assoc.	1	< 1	21	< 1	21
	Sol'n	1	< 1	7	< 1	7

Play Area 3 is characterized by stacked bar sequences in the Bow Island Formation. Log analysis problems resulting from the presence of fresh water may have resulted in a significant incidence of bypassed pay in some areas of this play. Additional gas is expected primarily from continued development of existing pools.

The undiscovered potential for this play area is estimated at 26.24 $\times$ 10^9 m^3 (932 Bcf), with estimates of the undiscovered pool size ranging up to 10 sections.

Play Area 4: Paddy and Cadotte – Bar Deposits – Northwestern Alberta
(e.g. Pouce Coupe South Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	41	22	32 528	78	10 - 315
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	143	78	9 438	22	1 - 841
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-

The Cadotte in Play Area 4 is characterized as a prograding barrier bar complex with tidal and estuarine channels. Gas is also found in overlying Paddy bar sandstones which are more restricted in areal extent than the Cadotte. To date, proven reserves have been discovered primarily in bar sandstones. However, recent drilling has focused on tidal and estuarine channel reservoirs. Due to the low density of drilling in portions of this play area, additional gas is expected primarily from new pools in tidal and estuarine sediments. Significant potential exists particularly in the channels. The lack of data and poor sandstone quality in the northeastern portion of the play area makes it difficult to assign potential.

The undiscovered potential for this play area is estimated at 53.20 $\times$ 10^9 m^3 (1889 Bcf), with estimates of the undiscovered pool size ranging up to 25 sections.

Play Area 5: Viking – Bar Deposits – West-Central Alberta
(e.g. Caroline Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	7	5	1 978	9	18 - 113
	Assoc.	12	8	6 261	29	<1 - 90
	Sol'n	30	20	8 530	39	<1 - 27
Two or less	Non-Assoc.	63	41	3 675	17	3 - 262
	Assoc.	12	8	529	2	5 - 128
	Sol'n	28	18	977	4	2 - 241

Viking bar sandstone development characterizes Play Area 5 which tends to be oil prone with substantial volumes of solution gas reserves. Substantial new additions of solution gas are not expected in the future due to the high drilling density in the eastern oil-prone area. Western portions of this play area, however, are less densely drilled and represent an area where additional gas is expected from new pools. The undiscovered gas potential is expected to be primarily associated and solution gas from deeper pools.

The undiscovered potential for this play area is estimated at 8.61×10^9 m^3 (306 Bcf), with estimates of the undiscovered pool size ranging up to five sections.

Ultimate Gas In Place

Viking Interval	Initial Gas In Place	Undiscovered 10^9 m^3				Ultimate Gas In Place
	10^9 m^3	GRC 1	GRC 2	GRC 3	Total	10^9 m^3
Play Area:						
1. Viking – Bar and Shelf Deposits – Central Alberta (e.g. Joarcam Field)	151.06	34.22	3.84	65.49	103.55	254.61
2. Viking – Shelf Deposits – East-Central Alberta (e.g. Provost Field)	167.54	19.84	0.67	1.88	22.39	189.93
3. Bow Island – Bar Deposits – Southern Alberta (e.g. Pendant d'Oreille Field)	50.85	14.89	2.08	9.27	26.24	77.09
4. Paddy and Cadotte – Bar Deposits – Northwestern Alberta (e.g. Pouce Coupe South Field)	41.97	18.10	6.30	28.80	53.20	95.17
5. Viking – Bar Deposits – West-Central Alberta (e.g. Caroline Field)	21.95	3.03	1.22	4.36	8.61	30.56
Play Area Totals	433.37	90.08	14.11	109.80	213.99	647.36

BASAL COLORADO INTERVAL

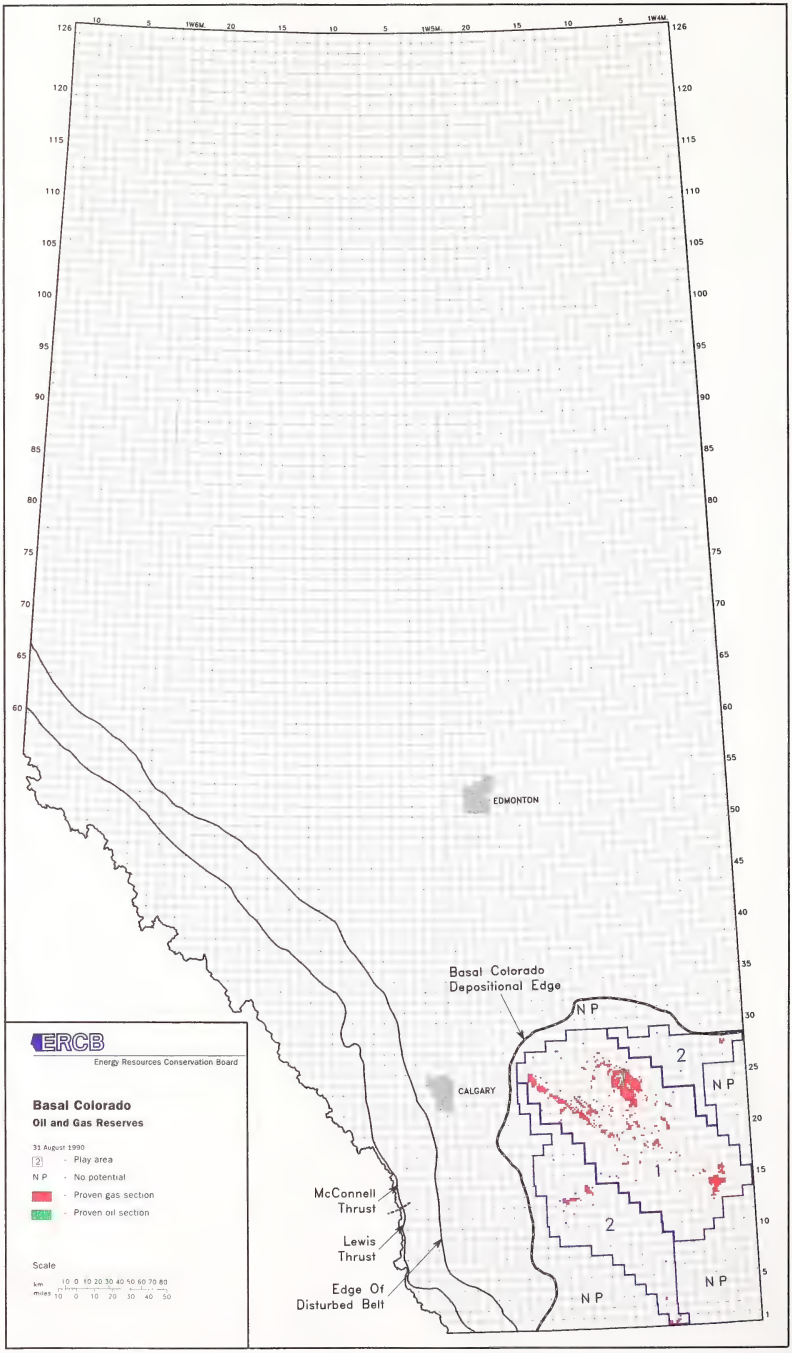

ERCB
Energy Resources Conservation Board
Basal Colorado
Oil and Gas Reserves
31 August 1990
2 · Play area
N P · No potential
· Proven gas section
· Proven oil section
Scale
km 10 0 10 20 30 40 50 60 70 80
miles 10 0 10 20 30 40 50
EDMONTON
CALGARY
Basal Colorado
Depositional Edge
McConnell
Thrust
Lewis
Thrust
Edge Of
Disturbed Belt
N P
2
1
W4M
W5M
W6M

FIGURE 11

D.11 Basal Colorado Interval

Reservoir Parameters:

Maximum Pay Thickness	7 metres
Porosity Range	10 to 32%
Pool Size Range	< 1 to 161 sections
Gas Saturation Range	35 to 90%
Recovery Factor Range	30 to 91%

Number of Play Areas = 2

Play Area 1: Well Developed Bar Deposits – Southeastern Alberta
(e.g. Cessford Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	30	21	13 411	35	4 - 105
	Assoc.	2	1	19 969	52	36 - 147
	Sol'n	1	1	544	1	12
Two or less	Non-Assoc.	105	74	4 112	11	3 - 227
	Assoc.	3	2	44	< 1	9 - 13
	Sol'n	-	-	-	-	-

Play Area 1 is characterized by the occurrence of large Basal Colorado pools in northwest-southeast trending bar sandstones. The play area is limited by the formation's depositional limit and the transition to the less developed bar sandstones of Play Area 2. The southeastern half of the play area is less densely drilled than the northwestern half. Therefore, additional gas is expected from development of existing pools in the northwest and discovery of new pools in the southeast.

The undiscovered potential for this play area is estimated at 20.92×10^9 m^3 (743 Bcf), with estimates of the undiscovered pool size ranging up to 15 sections.

Play Area 2: Poorly Developed Bar Deposits – Southeastern Alberta
(e.g. Sibbald Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	7	37	2 294	91	14 - 80
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	12	63	214	9	2 - 77
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-

Play Area 2 is characterized by the occurrence of smaller Basal Colorado pools in northwest-southeast trending bar sandstones. The play area is limited to the region immediately adjacent to Play Area 1.

Potential exists for both pool development and new pools. The undiscovered potential for this play area is estimated at 4.15×10^9 m^3 (147 Bcf), with estimates of the undiscovered pool size ranging up to 12 sections.

Ultimate Gas In Place

Basal Colorado Interval	Initial Gas In Place	Undiscovered 10^9 m^3				Ultimate Gas In Place
	10^9 m^3	GRC 1	GRC 2	GRC 3	Total	10^9 m^3
Play Area:						
1. Well Developed Bar Deposits – Southeastern Alberta (e.g. Cessford Field)	38.08	9.88	2.83	8.21	20.92	59.00
2. Poorly Developed Bar Deposits – Southeastern Alberta (e.g. Sibbald Field)	2.51	1.26	1.00	1.89	4.15	6.66
Play Area Totals	40.59	11.14	3.83	10.10	25.07	65.66

MANNVILLE ABOVE GLAUCONITIC INTERVAL

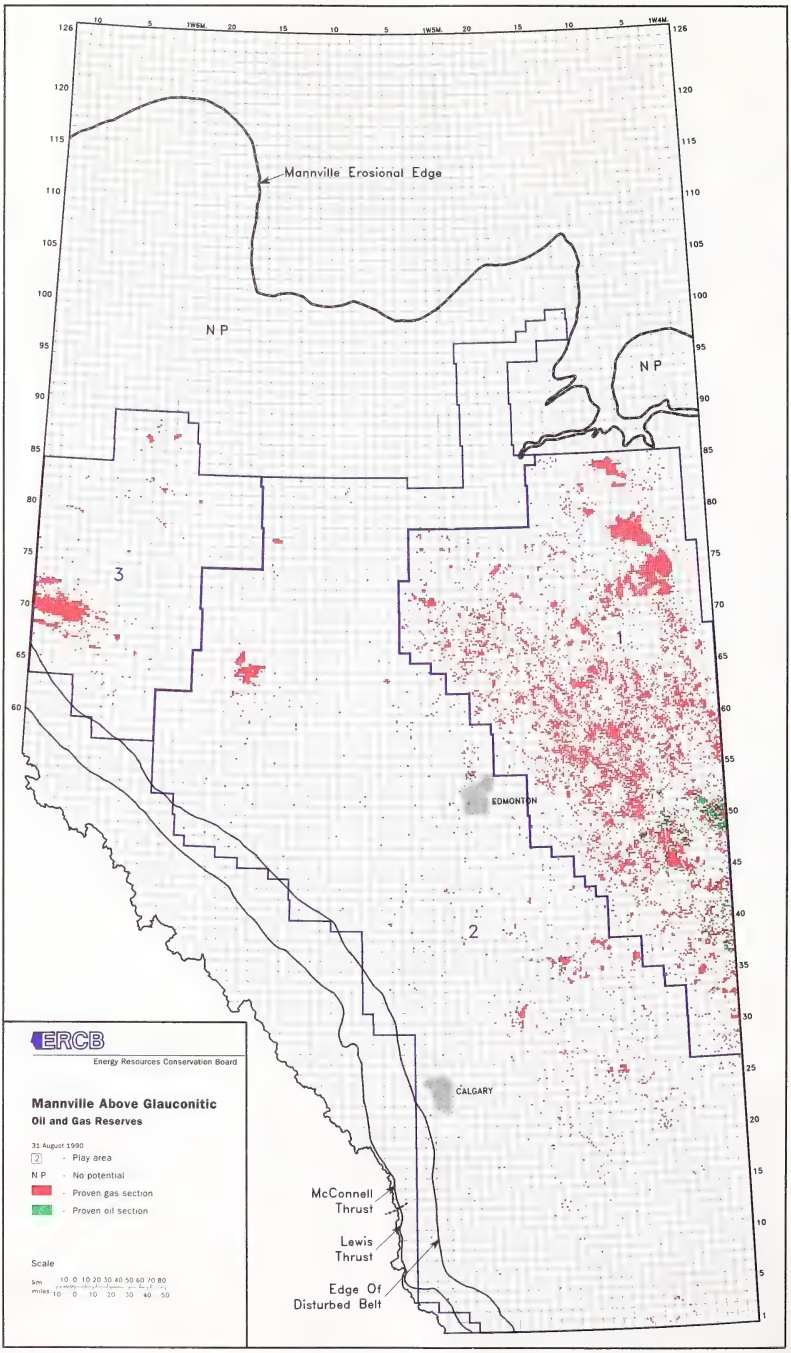

Mannville Erosional Edge
N P
N P
3
1
2
EDMONTON
CALGARY
McConnell Thrust
Lewis Thrust
Edge Of Disturbed Belt
ERCB
Energy Resources Conservation Board
Mannville Above Glauconitic
Oil and Gas Reserves
31 August 1990
2 - Play area
N P - No potential
- Proven gas section
- Proven oil section
Scale
km 10 0 10 20 30 40 50 60 70 80
miles 10 0 10 20 30 40 50

FIGURE 12

D.12 Mannville above Glauconitic Interval

Reservoir Parameters:

Maximum Pay Thickness	23 metres
Porosity Range	3 to 38%
Pool Size Range	< 1 to 268 sections (7 TWPs)
Gas Saturation Range	25 to 95%
Recovery Factor Range	5 to 95%

Constraints:

The Mannville above Glauconitic Interval is composed of nearshore, deltaic, and continental deposits which are of restricted lateral extent. As a result, the ultimate potential for zones included in the Mannville above Glauconitic stratigraphic package has been calculated as one interval, although multiple gas zones frequently occur in the same section.

The following zones are included in this stratigraphic interval:

- Grand Rapids Formation, including Grand Rapids, Colony, Waseca, McLaren, Sparky, General Petroleum, Rex, and Lloydminster Sands.
- Clearwater Formation, excluding the Wabiskaw Member.
- Mountain Park Formation.
- Spirit River Formation, including the Notikewin and Falher Members.
- Undifferentiated Mannville.

Method:

Potential was determined using the statistical method, described previously, for all play areas within the Mannville above Glauconitic stratigraphic interval. This approach was adopted for the following reasons: 1) the lack of lateral correlation of the strata involved; 2) the occurrence of multiple gas zones in a single wellbore; and 3) the high density of wells penetrating this stratigraphic interval. Bitumen wells were not used in the calculation of success rates as these wells tend to lower the overall success rates for gas to an unreasonable level.

Number of Play Areas = 3

Play Area 1: Colony, Grand Rapids and Heavy Oil Equivalents, Clearwater Bar and Channel Deposits – Eastern Alberta
(e.g. Lindbergh Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	508	10	145 542	52	< 1 - 200
	Assoc.	11	< 1	1 421	< 1	1 - 177
	Sol'n	34	1	5 697	2	< 1 - 63
Two or less	Non-Assoc.	4 187	85	124 531	44	< 1 - 612
	Assoc.	175	4	3 093	1	< 1 - 191
	Sol'n	19	< 1	386	< 1	1 - 188

Play Area 1 includes the Clearwater and Grand Rapids Formations which are composed of bar, deltaic and channel sandstones. Trapping mechanisms in these formations are a combination of structural and stratigraphic. Gas/water or gas/oil interfaces typically occur on the southwest extent of many pools, while the northern boundaries are controlled by facies changes. The Clearwater and Grand Rapids Formations are also important heavy oil or bitumen reservoirs. However, gas associated with this heavy crude is producible.

The undiscovered potential for this play area is estimated at 144.58×10^9 m^3 (5132 Bcf), with estimates of the undiscovered pool size ranging up to 15 sections.

Play Area 2: Upper Mannville Deposits – Southern and Central Alberta
(e.g. Kaybob Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	23	5	25 558	40	9 - 199
	Assoc.	5	1	6 977	11	12 - 132
	Sol'n	4	1	1 684	3	5 - 41
Two or less	Non-Assoc.	422	86	27 491	43	1 - 839
	Assoc.	20	4	1 216	2	1 - 204
	Sol'n	15	3	384	1	3 - 60

Play Area 2 consists of undifferentiated Mannville sandstones which occur throughout a large area of the province but individually are not laterally extensive (e.g. the informally named "Hackett Sands" in the Link Field). A notable exception is the large Notikewin pool in the Kaybob Field. Play Area 2 sandstones were deposited in a wide range of fluvial environments. The section is further characterized by the frequent, widespread occurrence of coal seams (e.g. the Medicine River Coal).

Most of the undiscovered gas is expected from the discovery of new pools. The undiscovered potential for this play area is estimated at 59.77×10^9 m^3 (2122 Bcf), with estimates of the undiscovered pool size ranging up to seven sections.

Play Area 3: Notikewin and Falher – Bar Deposits – Deep Basin
(e.g. Elmworth Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	34	14	52 407	69	9 - 416
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	202	86	23 183	31	1 - 1 836
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-

Play Area 3 is characterized by a prograding beach facies associated with a wave-dominated delta system. Multiple reservoir units can be encountered within a single well because of the Falher prograding coastal environment. Gas is trapped downdip (westward) from water-prone areas as is typical in the Lower Cretaceous of the Deep Basin. Additional gas is expected from both expansion of existing pools and discovery of new pools.

Most of the conventional gas reserves within the conglomerates is calculated based on cut-offs appropriate to current exploitation technology. However, tight gas (as discussed in Chapter 8) has also been recognized in the shoreface sandstones and siltstones, and may increase gas reserves significantly as economic conditions and technology improve.

The undiscovered conventional potential for this play area is estimated at 43.99×10^9 m^3 (1562 Bcf), with estimates of the undiscovered pool size ranging up to 10 sections.

Ultimate Gas In Place

Mannville above Glauconitic Interval	Initial Gas In Place	Undiscovered 10^9 m^3				Ultimate Gas In Place
	10^9 m^3	GRC 1	GRC 2	GRC 3	Total	10^9 m^3
Play Area:						
1. Colony, Grand Rapids and Heavy Oil Equivalents, Clearwater Bar and Channel Deposits – Eastern Alberta (e.g. Lindbergh Field)	280.67	39.14	10.25	95.19	144.58	425.25
2. Upper Mannville Deposits – Southern and Central Alberta (e.g. Kaybob Field)	63.31	19.57	3.27	36.93	59.77	123.08
3. Notikewin and Falher – Bar Deposits – Deep Basin (e.g. Elmworth Field)	75.59	10.44	3.14	30.41	43.99	119.58
Play Area Totals	419.57	69.15	16.66	162.53	248.34	667.91

GLAUCONITIC INTERVAL

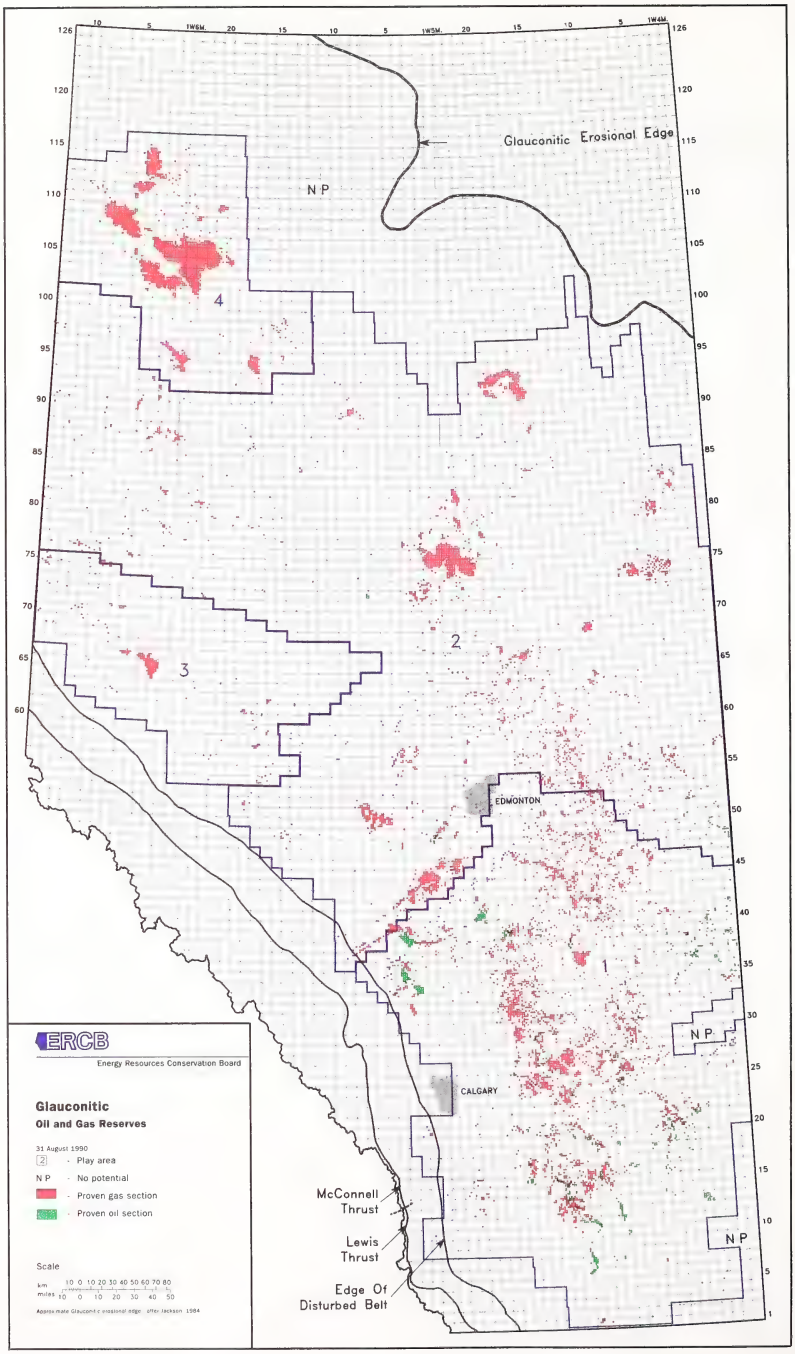

Glauconitic Erosional Edge
N P
4
3
2
1
EDMONTON
CALGARY
N P
N P
N P
McConnell Thrust
Lewis Thrust
Edge Of Disturbed Belt
ERCB
Energy Resources Conservation Board
Glauconitic
Oil and Gas Reserves
31 August 1990
2 - Play area
N P - No potential
- Proven gas section
- Proven oil section
Scale
km 10 0 10 20 30 40 50 60 70 80
miles 10 0 10 20 30 40 50
Approximate Glauconitic erosional edge after Jackson 1984

FIGURE 13

D.13 Glauconitic Interval

Reservoir Parameters:

Maximum Pay Thickness	27 metres
Porosity Range	3 to 36%
Pool Size Range	< 1 to 344 sections (10 TWPs)
Gas Saturation Range	20 to 90%
Recovery Factor Range	17 to 90%

Number of Play Areas = 4

Play Area 1: Glauconitic – Channel and Delta Deposits – Southern Alberta
(e.g. Wayne-Rosedale Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	146	8	97 730	43	7 - 416
	Assoc.	40	2	16 675	7	5 - 215
	Sol'n	68	4	18 185	8	1 - 129
Two or less	Non-Assoc.	1 384	72	84 964	37	1 - 781
	Assoc.	162	8	9 363	4	1 - 454
	Sol'n	109	6	3 197	1	1 - 138

The Glauconitic in this play area is represented by a progradational facies sequence which infilled the Ostracod basin. Reservoirs are composed of fluvial and estuarine channel and delta front sandstones. The gas is trapped by a combination of stratigraphy and structure. Since a number of Glauconitic sandstones within the same wellbore have proven productive in much of this play area, the method of determining potential is similar to that used for the Belly River.

The undiscovered potential for this play area is estimated at 123.03 $\times$ 10^9 m^3 (4367 Bcf), with estimates of the undiscovered pool size ranging up to 12 sections.

Play Area 2: Glauconitic, Cummings, Wabiskaw and Bluesky – Bar Deposits – Northeastern and Central Alberta
(e.g. Westerose Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	110	12	98 563	73	< 1 - 231
	Assoc.	-	-	-	-	-
	Sol'n	4	< 1	597	< 1	1 - 92
Two or less	Non-Assoc.	743	84	34 223	25	1 - 580
	Assoc.	21	2	577	< 1	3 - 83
	Sol'n	10	1	720	1	2 - 462

Play Area 2 is characterized by well defined marine bar deposits that typically have only one productive sandstone (e.g. Hoadley and Pembina pools). The main sediment supply source was from the south. Sediments were transported through the infilled Ostracod Basin and deposited in the wave-dominated Bluesky Sea resulting in northeast-southwest trending bar sandstones.

Additional gas is expected from new pools in areas of low drilling density. The undiscovered potential for this play area is estimated at 160.01×10^9 m^3 (5680 Bcf), with estimates of the undiscovered pool size ranging up to 20 sections.

Play Area 3: Bluesky – Bar Deposits – West-Central Alberta
(e.g. Karr Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	13	19	20 404	75	19 - 335
	Assoc.	-	-	-	-	-
	Sol'n	1	1	456	2	45
Two or less	Non-Assoc.	54	79	6 182	23	3 - 418
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-

Play Area 3 is characterized by deltaic sediments reworked into shallow marine bar sandstones as a result of transgressive events within the basin. Bluesky Formation sandstones are often quite clean because of the reworking action of marine processes. Currently, most pools in this play area are less than ten sections in size with the exception of the fault controlled Karr Bluesky "A" Pool which covers more than two townships.

Additional gas is expected both from expansion of existing pools and discovery of new pools. The undiscovered potential for this play area is estimated at 41.87 $\times$ 10^9 m^3 (1486 Bcf), with estimates of the undiscovered pool size ranging up to 10 sections.

Play Area 4: Bluesky — Barrier Bar Deposits — Northwestern Alberta
(e.g. Haro Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	25	22	43 941	95	2 - 112
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	87	78	2 089	5	2 - 171
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-

Play Area 4 is characterized by extensive barrier bar complexes located to the north of the shallow marine sediments of Play Area 2. The Bluesky Formation shales out quite rapidly to the northeast and is not deposited as barrier bar complexes to the southwest of the present Haro Field boundary. High shale volumes within the reservoirs result in substantially lower average IGIP values than in the other play areas. There are also a significant number of single section pools, discovered during the drilling for deeper Devonian targets, that have not as yet been fully delineated. Most of the undiscovered gas is therefore expected in GRC 1 as a result of step-out and development drilling of those single-section pools.

The undiscovered potential for this play area is estimated at 27.77 $\times$ 10^9 m^3 (986 Bcf), with estimates of the undiscovered pool size ranging up to 20 sections.

Ultimate Gas In Place

Glauconitic Interval	Initial Gas In Place	Undiscovered 10^9 m^3				Ultimate Gas In Place
	10^9 m^3	GRC 1	GRC 2	GRC 3	Total	10^9 m^3
Play Area:						
1. Glauconitic – Channel and Delta Deposits Southern Alberta (e.g. Wayne-Rosedale Field)	230.11	45.01	7.98	70.04	123.03	353.14
2. Glauconitic, Cummings, Wabiskaw and Bluesky – Bar Deposits – Northeastern and Central Alberta (e.g. Westerose Field)	134.68	29.37	11.68	118.96	160.01	294.69
3. Bluesky – Bar Deposits – West-Central Alberta (e.g. Karr Field)	27.04	13.31	3.98	24.58	41.87	68.91
4. Bluesky – Barrier Bar Deposits – Northwestern Alberta (e.g. Haro Field)	46.03	12.06	6.59	9.12	27.77	73.80
Play Area Totals	437.86	99.75	30.23	222.70	352.68	790.54

OSTRACOD
INTERVAL

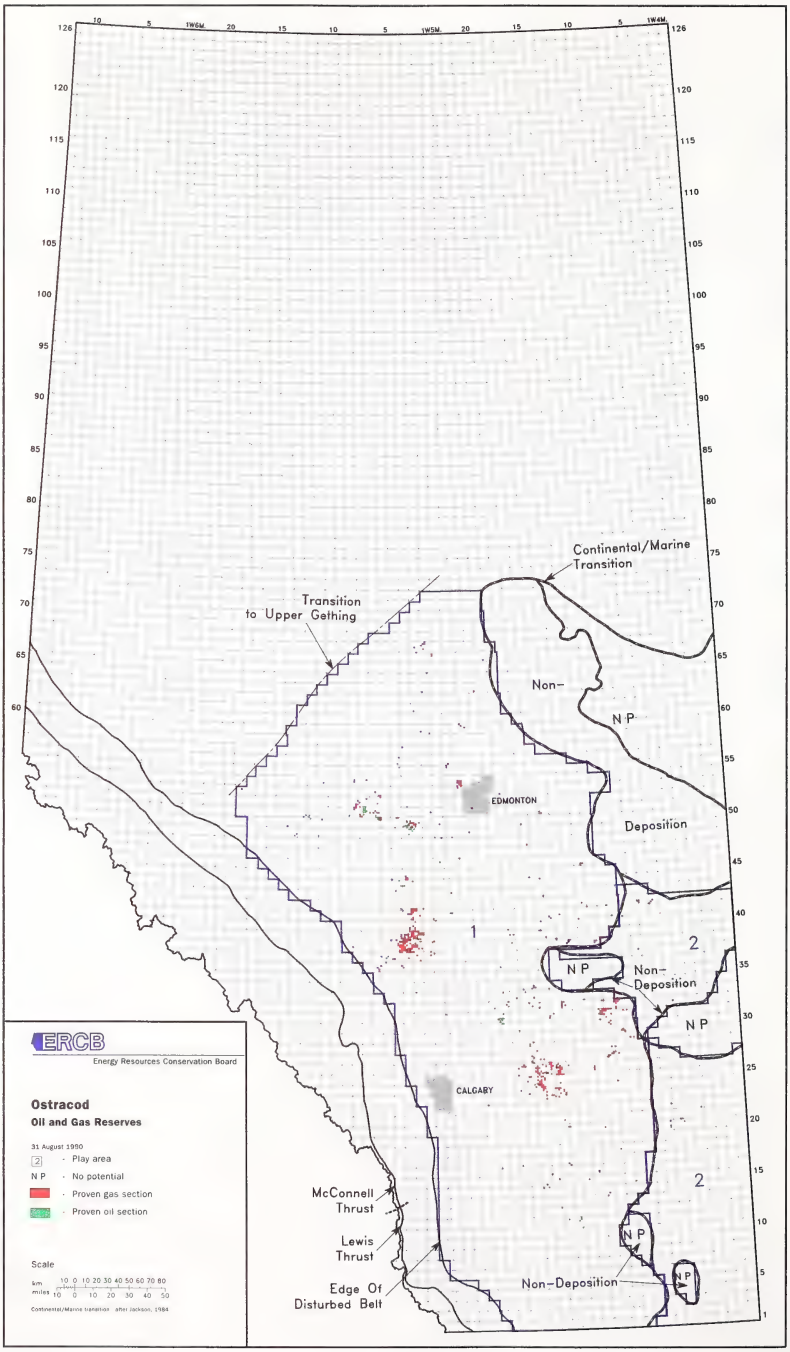

Continental/Marine Transition
Transition to Upper Gething
Non-
N P
EDMONTON
Deposition
1
2
N P
Non-Deposition
N P
CALGARY
2
McConnell Thrust
Lewis Thrust
Edge Of Disturbed Belt
N P
Non-Deposition
N P
ERCB
Energy Resources Conservation Board
Ostracod
Oil and Gas Reserves
31 August 1990
2 - Play area
N P - No potential
- Proven gas section
- Proven oil section
Scale
km 10 0 10 20 30 40 50 60 70 80
miles 10 0 10 20 30 40 50
Continental/Marine transition after Jackson, 1984

FIGURE 14

D.14 Ostracod Interval

Reservoir Parameters:

Maximum Pay Thickness	10 metres
Porosity Range	7 to 28%
Pool Size Range	< 1 to 22 sections
Gas Saturation Range	30 to 90%
Recovery Factor Range	5 to 90%

Number of Play Areas = 2

Play Area 1: Marine Deposits – Central Alberta
(e.g. Tomahawk Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	22	8	12 149	42	7 - 308
	Assoc.	9	3	3 941	13	6 - 180
	Sol'n	10	4	1 809	6	< 1 - 47
Two or less	Non-Assoc.	178	68	10 214	35	1 - 639
	Assoc.	17	7	504	2	3 - 94
	Sol'n	24	9	487	2	2 - 98

Play Area 1 is characterized by sediments deposited in various marine and coastal environments which were reworked by tidal processes. The play area is bounded by the shoreline of the restricted Ostracod Basin which has a large interior seaway open to the north and closed in the south. The current distribution of pools indicates that 68% of the total pools are single or two sections in size.

Potential for gas exists in development of those pools and in the discovery of new pools. The undiscovered potential for this play area is estimated at 42.00×10^9 m^3 (1491 Bcf), with estimates of the undiscovered pool size ranging up to 11 sections.

Play Area 2: Continental Deposits – Eastern Alberta
(e.g. Atlee-Buffalo Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	2	25	74	32	8 - 33
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	5	63	95	41	23 - 44
	Assoc.	-	-	-	-	-
	Sol'n	1	12	61	27	61

Play Area 2 is confined to the continental sediments on the eastern side of the Ostracod Basin. It is characterized by sediments associated mainly with lacustrine and fluvial environments. Within this area, regions with even minor relief resulted in a non-deposition and were therefore treated as areas of no potential.

The minimal discovery of reserves to date in this area leads to limited confidence in estimating undiscovered gas in place. Therefore, potential is assigned primarily to GRC 3. In GRC 1, wells with possible reserves contribute to the bulk of its undiscovered volume.

Additional gas is expected mainly from discovery of new pools. The undiscovered potential for this play area is estimated at 1.63×10^9 m^3 (58 Bcf), with estimates of the undiscovered pool size ranging up to four sections.

Ultimate Gas In Place

Ostracod Interval	Initial Gas In Place	Undiscovered 10^9 m^3				Ultimate Gas In Place
	10^9 m^3	GRC 1	GRC 2	GRC 3	Total	10^9 m^3
Play Area:						
1. Marine Deposits – Central Alberta (e.g. Tomahawk Field)	29.10	9.50	7.68	24.82	42.00	71.10
2. Continental Deposits – Eastern Alberta (e.g. Atlee-Buffalo Field)	0.23	0.08	0.00	1.55	1.63	1.86
Play Area Totals	29.33	9.58	7.68	26.37	43.63	72.96

ELLERSLIE
INTERVAL

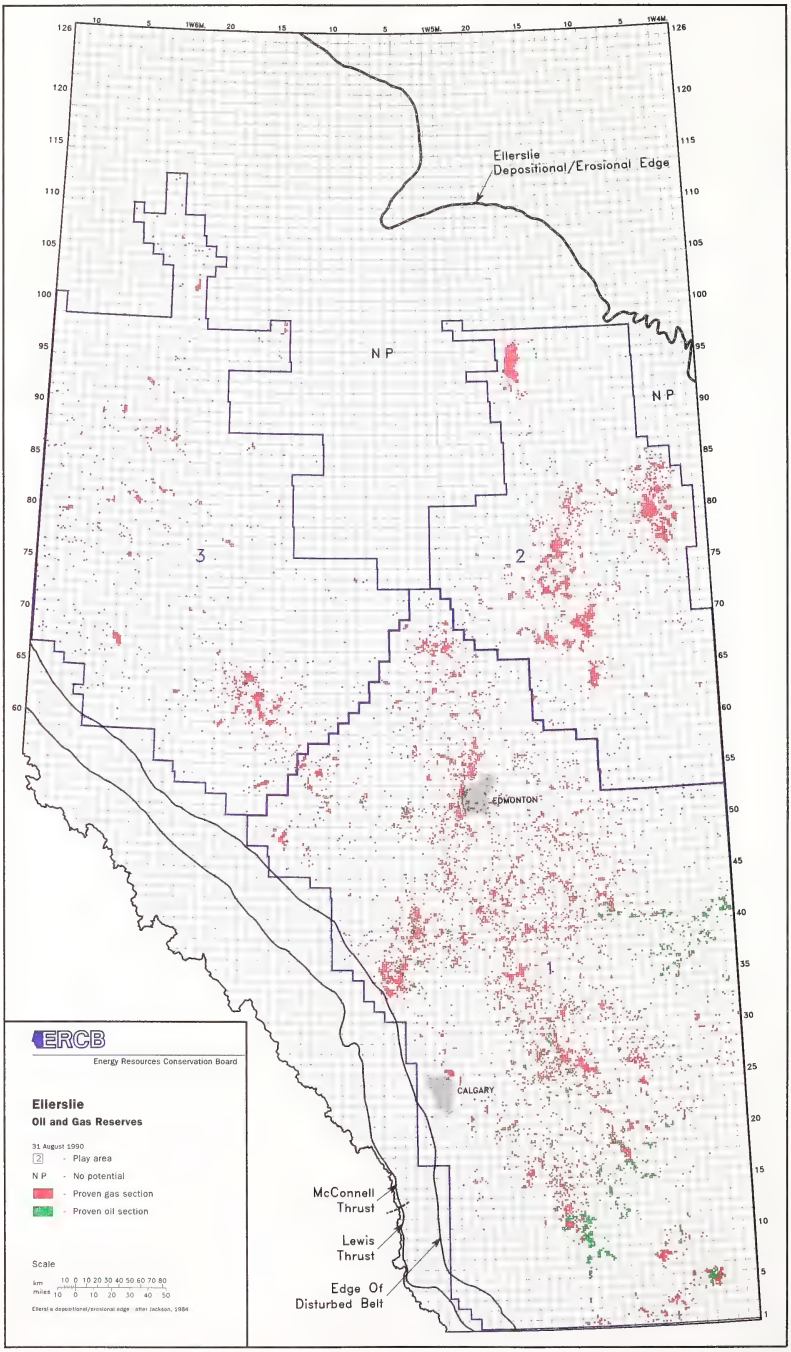

Ellerslie
Depositional/Erosional Edge
N P
N P
3
2
1
EDMONTON
CALGARY
McConnell
Thrust
Lewis
Thrust
Edge Of
Disturbed Belt
ERCB
Energy Resources Conservation Board
Ellerslie
Oil and Gas Reserves
31 August 1990
2 - Play area
N P - No potential
- Proven gas section
- Proven oil section
Scale
km 10 0 10 20 30 40 50 60 70 80
miles 10 0 10 20 30 40 50
Ellerslie depositional/erosional edge - after Jackson, 1984

FIGURE 15

D.15 Ellerslie Interval

Reservoir Parameters:

Maximum Pay Thickness	27 metres
Porosity Range	5 to 36%
Pool Size Range	<1 to 122 sections (3 TWPs)
Gas Saturation Range	20 to 95%
Recovery Factor Range	15 to 90%

Number of Play Areas = 3

Play Area 1: Ellerslie and Equivalents — Alluvial Deposits — South-Central Alberta
(e.g. Caroline Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	201	6	119 370	37	2 - 610
	Assoc.	57	2	18 950	6	<1 - 212
	Sol'n	87	3	17 114	5	1 - 355
Two or less	Non-Assoc.	2 583	76	153 351	47	1 - 700
	Assoc.	265	8	11 461	3	<1 - 279
	Sol'n	198	6	5 494	2	<1 - 577

Play Area 1 is characterized by alluvial plain deposits of the Ellerslie Formation. The trapping mechanism is primarily stratigraphic, but structural traps are also important. Most of the gas in this area occurs as non-associated gas pools. Minor amounts of associated and solution gas from oil pools are also present. Reservoirs in the western portions of this play area may contain tight gas resources.

Since multiple Ellerslie sandstones within the same wellbore have proven productive in much of this play area, the method of determining potential is similar to that used for the Belly River.

The undiscovered potential for this play area is estimated at 221.04×10^9 m^3 (7846 Bcf), with estimates of the undiscovered pool size ranging up to 10 sections.

Play Area 2: McMurray – Fluvial and Delta Deposits – Northeastern Alberta
(e.g. Chard Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	88	15	29 361	70	1 - 210
	Assoc.	1	<1	119	<1	39
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	504	84	11 992	29	1 - 251
	Assoc.	9	1	118	<1	3 - 29
	Sol'n	-	-	-	-	-

Play Area 2 is characterized by fluvio-deltaic sediments of the McMurray Formation of northeastern Alberta. Reservoirs in this area are shallow, poorly consolidated, and exhibit high porosity and permeability. Gas is trapped stratigraphically with water or bitumen downdip. High percentages of residual bitumen may also be present in the gas zones. Additional gas is expected from both new pools and pool expansion.

Within the area of townships 88-97, ranges 5-13W4, the 1 to 1 500 000 scale maps are missing data as a result of problems encountered retrieving information from oil sands wells. However, the analysis took into account all drilled sections which indicate no proven or potential gas reserves in this area.

The undiscovered potential for this play area is estimated at 43.93×10^9 m^3 (1560 Bcf), with estimates of the undiscovered pool size ranging up to 25 sections.

Play Area 3: Gething – Fluvial Deposits – Northwestern Alberta
(e.g. Gold Creek Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	34	6	33 559	41	10 - 321
	Assoc.	5	1	10 104	12	70 - 177
	Sol'n	3	< 1	632	1	27 - 46
Two or less	Non-Assoc.	493	89	36 473	44	1 - 561
	Assoc.	14	2	971	1	15 - 196
	Sol'n	5	1	231	< 1	4 - 129

Play Area 3 is limited to the Gething Formation in northwestern Alberta. Major river channels such as the Edmonton and Spirit River Channels not only provided a sediment source, but also affected sedimentation patterns in this play area. As with the Falher and Cadomin, Gething reservoirs in the Deep Basin are typified by updip water. The Gething Formation is also known to contain tight gas resources in the western portion of the play area. Most of the pools in this play area are non-associated, and most of the undiscovered gas is also expected from non-associated gas in new pools.

The undiscovered potential for this play area is estimated at 139.10×10^9 m^3 (4938 Bcf), with estimates of the undiscovered pool size ranging up to 15 sections.

Ultimate Gas In Place

Ellerslie Interval	Initial Gas In Place	Undiscovered 10^9 m^3				Ultimate Gas In Place
	10^9 m^3	GRC 1	GRC 2	GRC 3	Total	10^9 m^3
Play Area:						
1. Ellerslie and Equivalents – Alluvial Deposits – South-Central Alberta (e.g. Caroline Field)	325.74	79.34	14.53	127.17	221.04	546.78
2. McMurray – Fluvial and Delta Deposits – Northeastern Alberta (e.g. Chard Field)	41.59	17.23	8.41	18.29	43.93	85.52
3. Gething – Fluvial Deposits – Northwestern Alberta (e.g. Gold Creek Field)	81.97	38.88	27.93	72.29	139.10	221.07
Play Area Totals	449.30	135.45	50.87	217.75	404.07	853.37

CADOMIN
INTERVAL

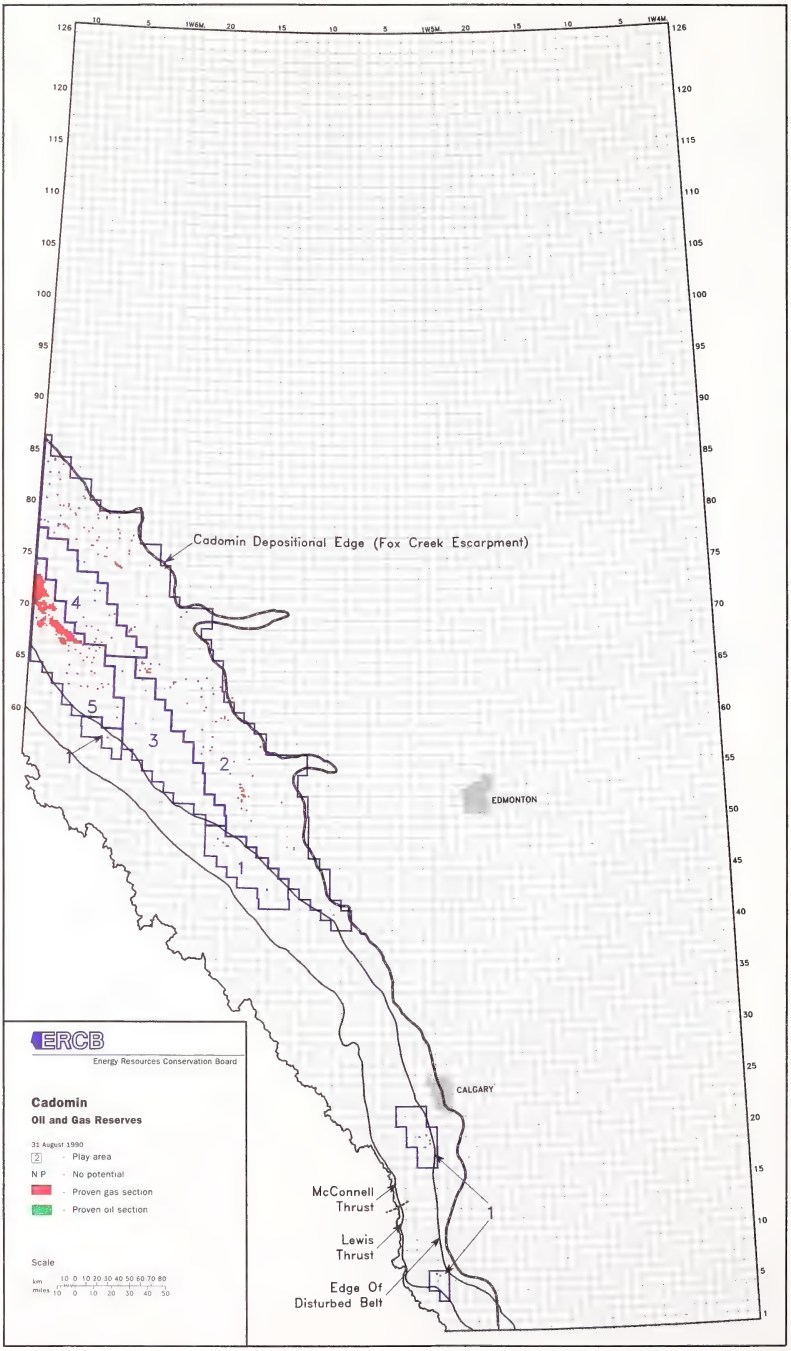

Cadomin Depositional Edge (Fox Creek Escarpment)
EDMONTON
CALGARY
McConnell Thrust
Lewis Thrust
Edge Of Disturbed Belt
ERCB
Energy Resources Conservation Board
Cadomin
Oil and Gas Reserves
31 August 1990
Play area
No potential
Proven gas section
Proven oil section
Scale

FIGURE 16

D.16 Cadomin Interval

Reservoir Parameters:

Maximum Pay Thickness	24 metres
Porosity Range	4 to 23%
Pool Size Range	< 1 to 169 sections
Gas Saturation Range	45 to 90%
Recovery Factor Range	50 to 90%

Number of Play Areas = 5

Play Area 1: Foothills
(e.g. Mountain Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	-	-	-	-	-
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	15	100	1 410	100	7 - 380
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-

In Play Area 1, the Cadomin is deposited as a series of alluvial fans consisting of coarse sandstones and conglomerates. Play Area 1 is restricted to four fan deposits within the Disturbed Belt adjacent to the Cordillera. Within these fans, potential is further limited by the lack of structural closure. Also, porosity is diminished by compaction due to depth of burial and by silicification which is a common process. No potential exists between the fans because Cadomin sediments either eroded or were not deposited.

The Cadomin was productive in a few structures that were drilled for Mississippian. A relationship appears to exist between Mississippian structures, productive Cadomin and the potential for Cadomin gas within the alluvial fans. Therefore, an occurrence ratio was developed which relates existing structures containing Cadomin gas to existing Mississippian structures. The expected number of potential Mississippian structures within the areal extent of fan deposition was multiplied by this ratio to determine the potential volume for gas in the Cadomin. Additional gas is expected from new pools associated with deeper drilling for Mississippian targets and additional gas could also be found if Cadomin structures were specifically targeted.

The undiscovered potential for this play area is estimated at 2.28×10^9 m^3 (81 Bcf), with estimates of the undiscovered pool size ranging up to four sections.

Play Area 2: Fluvial Deposits Within the Spirit River Channel – Northwestern Alberta
(e.g. Edson Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	7	6	3 892	29	64 - 177
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	102	92	9 372	69	1 - 370
	Assoc.	2	2	186	1	38 - 148
	Sol'n	-	-	-	-	-

Play Area 2 is that portion of the Spirit River channel that is bounded to the south by the increased occurrence of shaly sandstone, to the east by the Fox Creek Escarpment and to the west by the alluvial plain facies. Sediments from the alluvial plain were shed into the Spirit River channel system and subsequently reworked in a braided river environment. The resulting conglomerates and sandstones are well sorted. Traps are stratigraphic and structural, dependant upon their location within the channel.

Additional gas is expected from the discovery of new pools. The undiscovered potential for this play area is estimated at 49.13×10^9 m^3 (1744 Bcf), with estimates of the undiscovered pool size ranging up to two sections.

Play Area 3: Poorly Developed Alluvial Deposits – Deep Basin

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	-	-	-	-	-
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	2	100	182	100	84 - 98
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-

Play Area 3 is characterized by poorly sorted sediments within the alluvial plain facies. The play area is confined to that portion of the alluvial plain that exists between the bifurcated Spirit River Channel. The minimal discovery of reserves to date in this area leads to limited confidence in estimating undiscovered GIP. Therefore, potential is only assigned to GRC 3.

The undiscovered potential for this play area is estimated at 4.46×10^9 m^3 (158 Bcf), with estimates of the undiscovered pool size ranging up to three sections.

Play Area 4: Fluvial Deposits – Water Prone – Deep Basin
(e.g. Elmworth Field – Cadomin B Pool)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	-	-	-	-	-
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	12	100	1 430	100	24 - 600
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-

Play Area 4 is characterized by conglomeratic deposits related to the intermingling of the Spirit River Channel and alluvial plain facies. It is limited to water-prone clastic sediments west of the Spirit River channel, east of the updip water of the Deep Basin and by Play Area 3 in the south. Hydrodynamics play an important role in hydrocarbon distribution and trapping within this play area.

Additional gas is expected both from expansion of existing pools and the discovery of new pools. The undiscovered potential for this play area is estimated at 3.85×10^9 m^3 (137 Bcf), with estimates of the undiscovered pool size ranging up to two sections.

Play Area 5: Braided Channel Deposits – Deep Basin
(e.g. Elmworth Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	6	15	22 650	86	12 - 74
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	35	85	3 540	14	17 - 810
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-

Play Area 5 consists of conglomerates deposited in proximal to medial braided river facies in the western portion of the bifurcated Spirit River Channel. This play area is limited to the northeast by updip water. The play area does not display conventional trapping in that there is gas trapped downdip from water. The mechanism of the trap has been postulated by Masters (1979) as a hydrodynamic trap and Thompson (1989) as converging flow paths of natural gas and water. Potential exists to the south of the multi-well pools where the braided river deposits should coalesce to form continuous reservoirs as in the north.

Many single-section pools in the southern portion are not fully delineated and, therefore, additional gas is expected from both pool expansion and new pools. The undiscovered potential for this play area is estimated at 48.56×10^9 m^3 (1724 Bcf), with estimates of the undiscovered pool size ranging up to five sections.

Ultimate Gas In Place

Cadomin Interval	Initial Gas In Place	Undiscovered 10^9 m^3				Ultimate Gas In Place
	10^9 m^3	GRC 1	GRC 2	GRC 3	Total	10^9 m^3
Play Area:						
1. Foothills (e.g. Mountain Field)	1.41	0.78	0.29	1.21	2.28	3.69
2. Fluvial Deposits within the Spirit River Channel – Northwestern Alberta (e.g. Edson Field)	13.45	16.44	4.57	28.12	49.13	62.58
3. Poorly Developed Alluvial Deposits – Deep Basin	0.18	0.00	0.00	4.46	4.46	4.64
4. Fluvial Deposits – Water Prone – Deep Basin (e.g. Elmworth Field – Cadomin B Pool)	1.43	1.35	0.81	1.69	3.85	5.28
5. Braided Channel Deposits – Deep Basin (e.g. Elmworth Field)	26.19	23.19	4.25	21.12	48.56	74.75
Play Area Totals	42.66	41.76	9.92	56.60	108.28	150.94

NIKANASSIN
INTERVAL

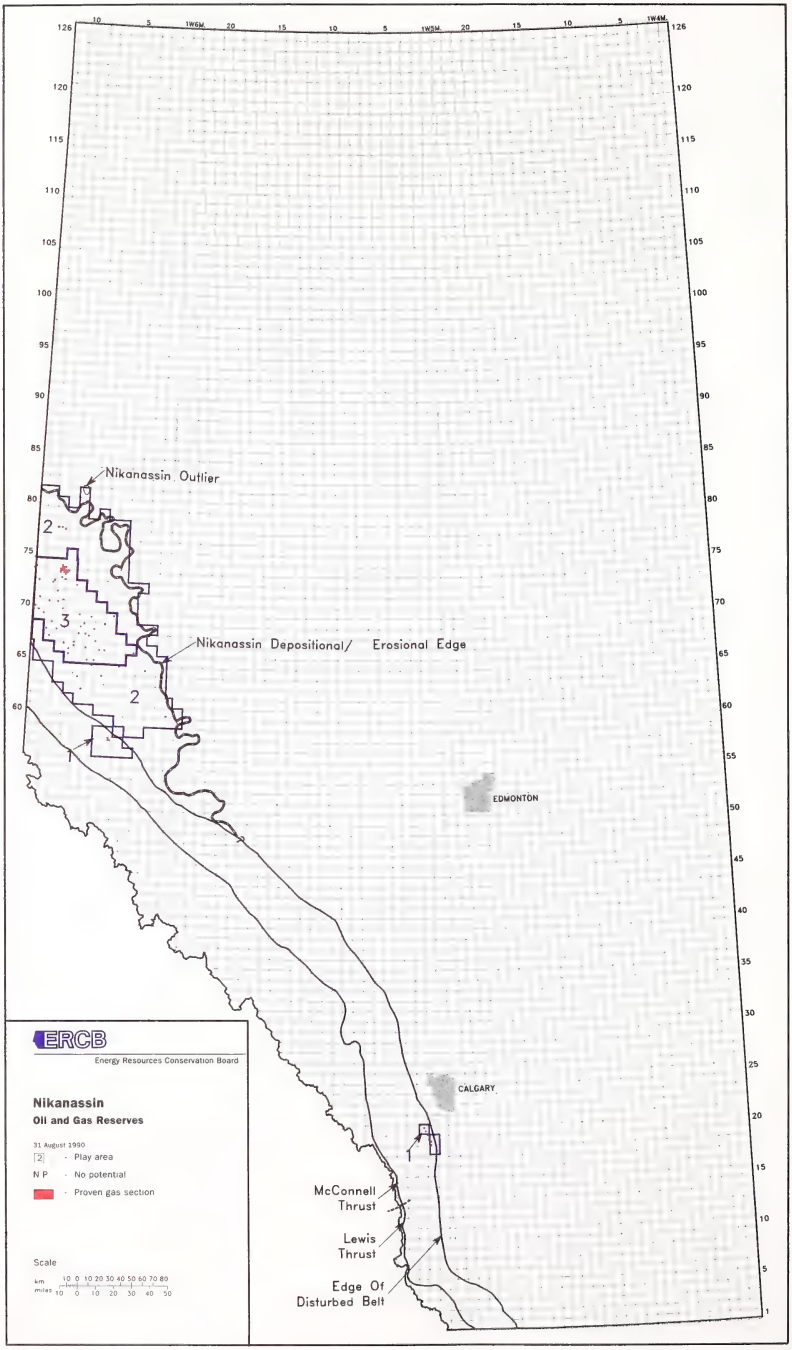

Nikanassin Outlier
Nikanassin Depositional/ Erosional Edge
2
3
2
1
EDMONTON
CALGARY
1
McConnell Thrust
Lewis Thrust
Edge Of Disturbed Belt
ERCB
Energy Resources Conservation Board
Nikanassin
Oil and Gas Reserves
31 August 1990
2 - Play area
N P - No potential
- Proven gas section
Scale
km 10 0 10 20 30 40 50 60 70 80
miles 10 0 10 20 30 40 50

FIGURE 17

D.17 Nikanassin Interval

Reservoir Parameters:

Maximum Pay Thickness	19 metres
Porosity Range	8 to 18%
Pool Size Range	< 1 to 17 sections
Gas Saturation Range	55 to 90%
Recovery Factor Range	50 to 85%

Number of Play Areas = 3

Play Area 1: Foothills
(e.g. Findley Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	-	-	-	-	-
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	9	82	596	93	11 - 146
	Assoc.	1	9	15	2	15
	Sol'n	1	9	27	4	15

Play Area 1 is characterized by Nikanassin Formation distributary channel sandstones. Gas occurs locally in structurally controlled pools within the Disturbed Belt. Due to the minor amount of reserves and small amount of data, the play area boundaries are limited to a step-out of approximately one township. Since reserves have been discovered while drilling for deeper targets, potential was determined using the same method as for the Cadomin in Play Area 1. Similar to the Cadomin, the porosity of the Nikanassin sandstones is reduced by compaction, which is a function of burial and silicification.

Additional gas is expected primarily from both pool expansion and new pools. The undiscovered potential for this play area is estimated at 0.65×10^9 m^3 (23 Bcf), with estimates of the undiscovered pool size ranging up to three sections.

Play Area 2: Distributary Channel Deposits – Northwestern Alberta

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	-	-	-	-	-
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	10	100	1 325	100	16 - 272
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-

Play Area 2 is limited by the more distal reaches of the distributary channel system and to the south by the deeper portion of the basin. Sediments were deposited in stream channels as poorly developed sands with increased amounts of lithic fragments and dispersed clays. Chemical alteration and mechanical compaction of those fragments and clays has significantly reduced porosity and permeability of the rock resulting in sandstones that are considered to be mostly tight gas sandstones.

The minimal discovery of reserves in this area to date leads to assigning undiscovered reserves only to GRC 3 and these would, therefore, be new pool discoveries. In GRC 1, wells with possible reserves contribute to the bulk of its undiscovered volume.

The undiscovered potential for this play area is estimated at 3.13×10^9 m^3 (111 Bcf), with estimates of the undiscovered pool size ranging up to two sections.

Play Area 3: Braided Channel Deposits – Northwestern Alberta
(e.g. Knopcik Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	1	2	1 563	15	91
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	47	98	9 216	85	39 - 793
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-

Play Area 3 is characterized by well developed sandstones deposited within a braided channel system. The limits of the play area are controlled by the increasing impact of marine influences on the fluvial environment. Most of the IGIP is found in pools which are one or two sections in size. It is expected that most of the undiscovered gas will result from expansion of these pools.

The undiscovered potential for this play area is estimated at 44.67 $\times$ 10^9 m^3 (1586 Bcf), with estimates of the undiscovered pool size ranging up to five sections.

Ultimate Gas In Place

Nikanassin Interval	Initial Gas In Place	Undiscovered 10^9 m^3				Ultimate Gas In Place
	10^9 m^3	GRC 1	GRC 2	GRC 3	Total	10^9 m^3
Play Area:						
1. Foothills (e.g. Findley Field)	0.64	0.26	0.06	0.33	0.65	1.29
2. Distributary Channel Deposits – Northwestern Alberta	1.33	0.20	0.00	2.93	3.13	4.46
3. Braided Channel Deposits – Northwestern Alberta (e.g. Knopcik Field)	10.78	21.33	6.96	16.38	44.67	55.45
Play Area Totals	12.75	21.79	7.02	19.64	48.45	61.20

ROCK CREEK
INTERVAL

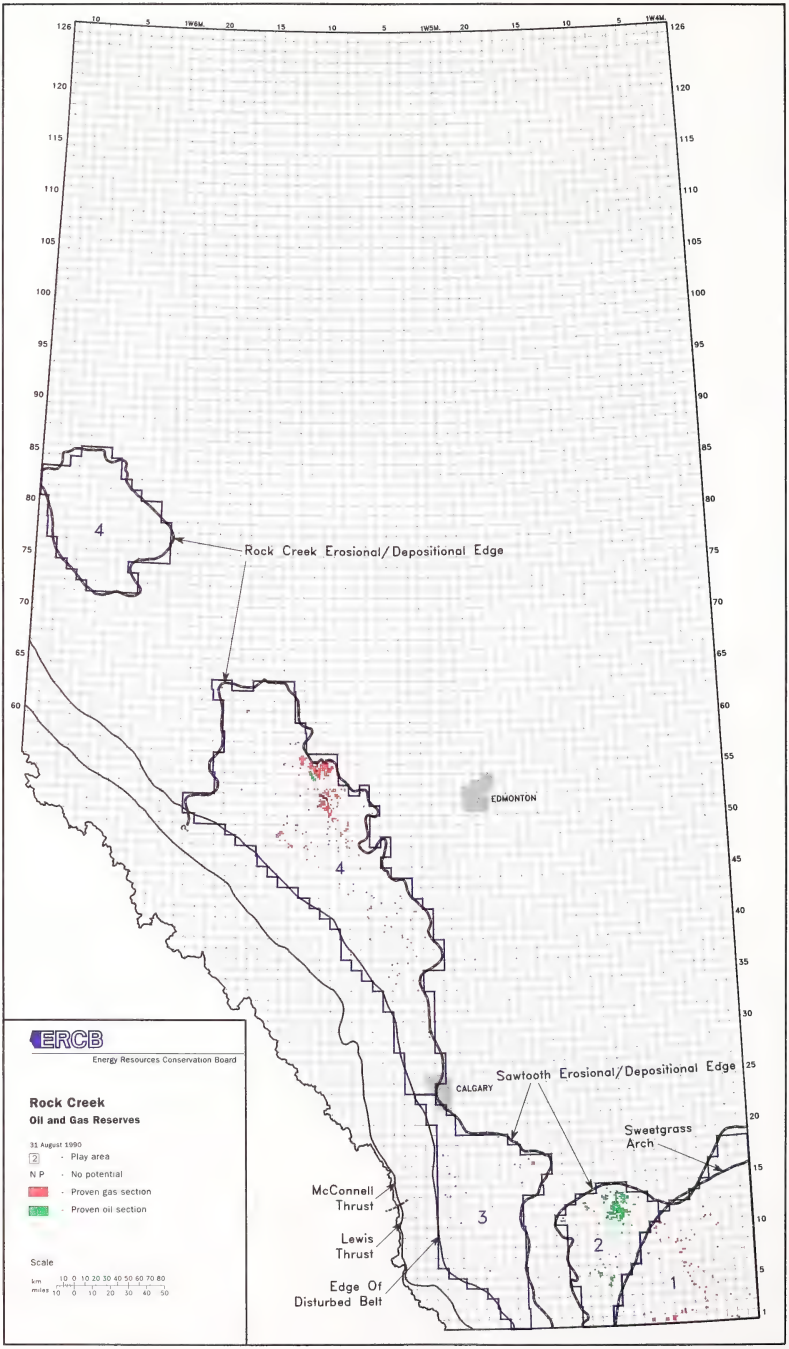

ERCB
Energy Resources Conservation Board
Rock Creek
Oil and Gas Reserves
31 August 1990
2 - Play area
N P - No potential
- Proven gas section
- Proven oil section
Scale
km 10 0 10 20 30 40 50 60 70 80
miles 10 0 10 20 30 40 50
4
Rock Creek Erosional/Depositional Edge
EDMONTON
4
CALGARY
Sawtooth Erosional/Depositional Edge
Sweetgrass Arch
McConnell Thrust
Lewis Thrust
Edge Of Disturbed Belt
3
2
1

FIGURE 18

D.18 Rock Creek Interval

Reservoir Parameters:

Maximum Pay Thickness	37 metres
Porosity Range	6 to 29%
Pool Size Range	< 1 to 16 sections
Gas Saturation Range	30 to 90%
Recovery Factor Range	42 to 90%

Number of Play Areas = 4

Play Area 1: Swift and Sawtooth — Shelf and Bar Deposits — Gas Prone — Southeastern Alberta (e.g. Black Butte Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	4	8	1 346	38	15 - 128
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	44	86	1 946	56	1 - 274
	Assoc.	2	4	180	5	58 - 64
	Sol'n	1	2	38	1	38

The Play Area 1 boundary encompasses Swift and Sawtooth Formation sediments east of the Sweetgrass Arch. The marine bar and sheet sandstones of the Swift and the beach and shallow marine shelf sandstones of the Sawtooth are gas prone in this play area.

Additional gas is expected from existing pool development and the discovery of new pools. The undiscovered potential for this play area is estimated at 13.36×10^9 m^3 (474 Bcf), with estimates of the undiscovered pool size ranging up to four sections.

Play Area 2: **Sawtooth — Shelf Deposits — Oil Prone — Southeastern Alberta**
(e.g. Grand Forks Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	-	-	-	-	-
	Assoc.	-	-	-	-	-
	Sol'n	9	69	519	94	2 - 11
Two or less	Non-Assoc.	-	-	-	-	-
	Assoc.	1	8	10	2	10
	Sol'n	3	23	24	4	4 - 5

Play Area 2 is characterized by shelf deposits of the Sawtooth Formation west of Play Area 1. The play area is bounded to the west by the eastern edge of the Cutbank Formation. Since the Sawtooth reservoirs are oil prone, pool development and the discovery of new pools will provide additional solution gas.

The undiscovered potential for this play area is estimated at 0.14×10^9 m^3 (5 Bcf), with estimates of the undiscovered pool size ranging up to four sections.

Play Area 3: **Swift and Sawtooth — Marine Deposits — Gas Prone — Southwestern Alberta**
(e.g. Long Coulee Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	1	14	496	49	124
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	6	86	510	51	10 - 185
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-

Play Area 3 is confined between the western edge of the Cutbank Formation and the eastern edge of the Disturbed Belt. The northern limit of the play area represents a change in nomenclature from

Sawtooth Formation to Rock Creek Member. Deposition took place in a deeper marine setting and Swift and Sawtooth Formation sediments consist primarily of fine grained sandstones and siltstones.

Additional gas is expected from both pool development and the discovery of new pools. The undiscovered potential for this play area is estimated at 10.97×10^9 m^3 (389 Bcf), with estimates of the undiscovered pool size ranging up to four sections.

Play Area 4: Rock Creek – Shelf and Bar Deposits – Central and Northwestern Alberta
(e.g. Niton Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	15	11	11 886	31	15 - 331
	Assoc.	5	4	10 796	28	34 - 165
	Sol'n	6	4	2 257	6	12 - 46
Two or less	Non-Assoc.	89	64	12 197	32	9 - 571
	Assoc.	11	8	550	2	4 - 106
	Sol'n	13	9	294	1	2 - 42

Play Area 4 is characterized by Rock Creek Member sheet sandstones deposited on a marine shelf. The play area is divided into two by Fernie Formation shales in a depositional low between townships 64 and 71. The southern portion is defined by the eastern edge of the Disturbed Belt and the Rock Creek Member erosional edge. The northern portion is limited by the depositional and erosional edge of the shelf sandstones.

Development of existing pools and discovery of new pools along the erosional edge is expected to add most of the additional gas. However, potential also exists for additional gas downdip from the erosional edge as evidenced by recent developments in the Edson and Ansell Fields.

The undiscovered potential for this play area is estimated at 63.20×10^9 m^3 (2244 Bcf), with estimates of the undiscovered pool size ranging up to six sections.

Ultimate Gas In Place

Rock Creek Interval	Initial Gas In Place	Undiscovered 10^9 m^3				Ultimate Gas In Place
	10^9 m^3	GRC 1	GRC 2	GRC 3	Total	10^9 m^3
Play Area:						
1. Swift and Sawtooth – Shelf and Bar Deposits – Gas Prone – Southeastern Alberta (e.g. Black Butte Field)	3.51	2.22	1.67	9.47	13.36	16.87
2. Sawtooth – Shelf Deposits – Oil Prone – Southeastern Alberta (e.g. Grand Forks Field)	0.55	0.12	0.00	0.02	0.14	0.69
3. Swift and Sawtooth – Marine Deposits – Gas Prone – Southwestern Alberta (e.g. Long Coulee Field)	1.01	1.37	0.55	9.05	10.97	11.98
4. Rock Creek – Shelf and Bar Deposits – Central and Northwestern Alberta (e.g. Niton Field)	37.98	27.73	5.65	29.82	63.20	101.18
Play Area Totals	43.05	31.44	7.87	48.36	87.67	130.72

NORDEGG
INTERVAL

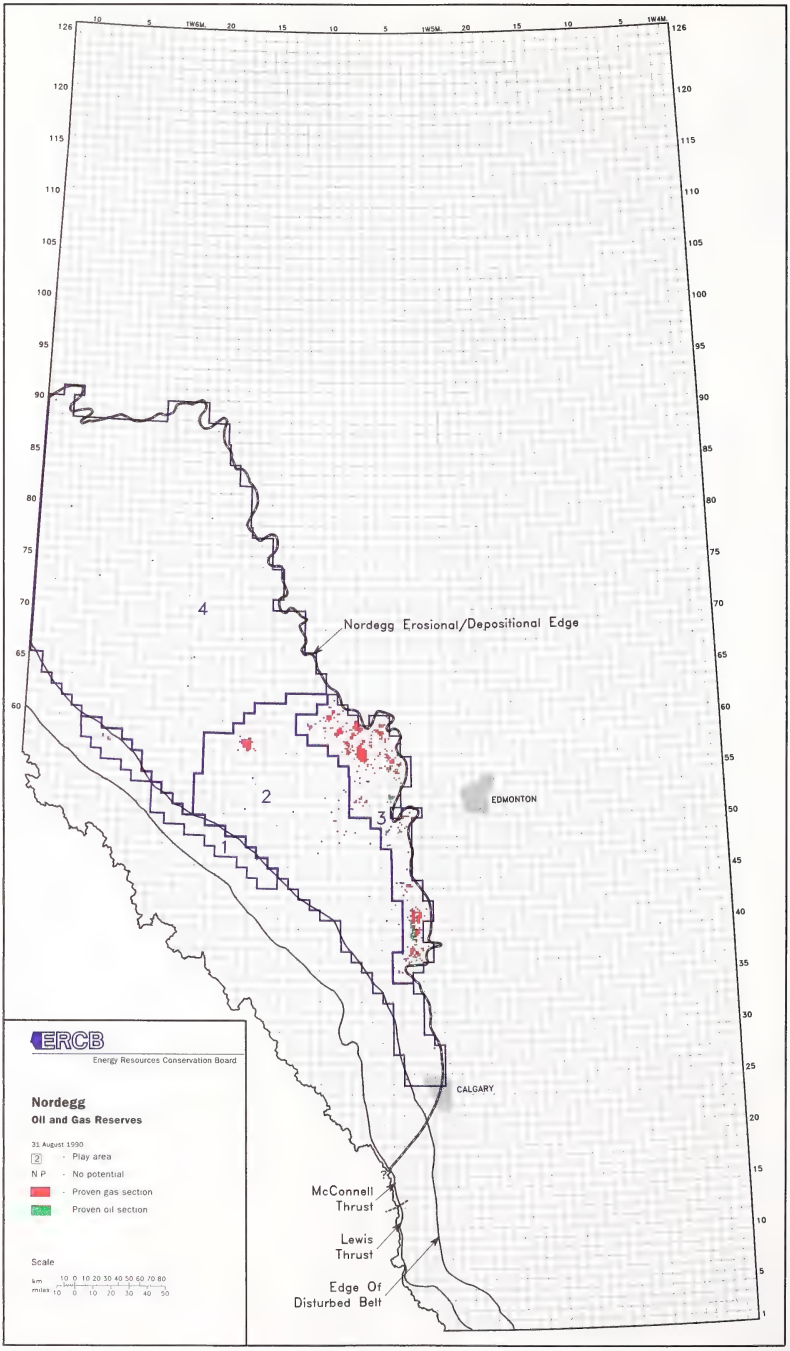

Nordegg Erosional/Depositional Edge
EDMONTON
CALGARY
McConnell Thrust
Lewis Thrust
Edge Of Disturbed Belt
4
2
3
1
ERCB
Energy Resources Conservation Board
Nordegg
Oil and Gas Reserves
31 August 1990
2 · Play area
N P · No potential
· Proven gas section
· Proven oil section
Scale
km
miles

FIGURE 19

D.19 Nordegg Interval

Reservoir Parameters:

Maximum Pay Thickness	28 metres
Porosity Range	5 to 30%
Pool Size Range	< 1 to 58 sections
Gas Saturation Range	35 to 90%
Recovery Factor Range	40 to 90%

Number of Play Areas = 4

Play Area 1: Foothills
(e.g. Findley Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	1	25	496	52	208
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	3	75	454	49	104 - 224
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-

Play Area 1 is characterized by deep marine shales, siltstones and local occurrences of fine sandstone lenses. The play is limited by the eastern edge of the Disturbed Belt north of township 44. Stratigraphic and structural traps control the occurrence of hydrocarbon reservoirs. Structural closure for the Nordegg Formation is most often related to underlying Mississippian structures. Since the more lucrative Mississippian is a primary target in this area, significant potential for undiscovered gas in the Nordegg is predicted.

Potential was estimated using the same method described for the Cadomin in Play Area 1.

The undiscovered potential for this play area is estimated at 7.32×10^9 m^3 (260 Bcf), with estimates of the undiscovered pool size ranging up to five sections.

Play Area 2: Phosphatic Limestones – West-Central Alberta
(e.g. Pine Creek Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	1	5	4 741	59	138
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	16	80	3 252	40	21 - 655
	Assoc.	1	5	6	<1	6
	Sol'n	2	10	1	1	8 - 53

Play Area 2 is characterized by marine phosphatic shales, siltstones and limestones. The play area is bounded to the east by the shoreface sandstone facies of Play Area 3 and to the west by the Disturbed Belt. It is further limited to the north by a transition to shale. Local sporadic porosity development, primarily within the limestone facies, accounts for most of the gas pools in this play area. However, the structurally controlled Pine Creek Nordegg Pool also occurs in this area. The Nordegg has not been a target in this area due to its unpredictable porosity development. Therefore, the potential is expected primarily from new pools.

The undiscovered potential for this play area is estimated at 28.56×10^9 m^3 (1014 Bcf), with estimates of the undiscovered pool size ranging up to three sections.

Play Area 3: Shoreface Deposits – Central Alberta
(e.g. Cherhill Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	17	10	32 115	57	15 - 888
	Assoc.	11	6	3 643	6	37 - 94
	Sol'n	16	9	5 884	10	6 - 104
Two or less	Non-Assoc.	98	55	12 198	22	3 - 595
	Assoc.	23	13	2 214	4	2 - 441
	Sol'n	12	7	526	1	14 - 92

The major productive facies in Play Area 3 is chert-rich, shoreline sandstones. The play area is limited to the east by the Nordegg erosional edge. Extensive drilling along this edge, where Mississippian oil pools are the primary target, has led to discovery of the reservoirs in the Cherhill, Whitecourt and Paddle River Fields. However, the western edge of the shoreline facies has not been completely delineated. Therefore, additional gas is expected from both pool expansion and the discovery of new pools.

The undiscovered potential for this play area is estimated at 30.56×10^9 m^3 (1085 Bcf), with estimates of the undiscovered pool size ranging up to seven sections.

Play Area 4: Shoreface Deposits – Peace River Arch

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	-	-	-	-	-
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	4	100	468	100	27 - 194
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-

Play Area 4 consists of basinal phosphatic shales, siltstones and detrital sandstones. It is characterized by sporadic porosity development in rather thin pay zones. This play area was assessed with GRC 3 potential because of the poor reserve distribution to date.

The undiscovered potential for this play area is estimated at 1.87×10^9 m^3 (66 Bcf), with estimates of the undiscovered pool size ranging up to three sections.

Ultimate Gas In Place

Nordegg Interval	Initial Gas In Place	Undiscovered 10^9 m^3				Ultimate Gas In Place
	10^9 m^3	GRC 1	GRC 2	GRC 3	Total	10^9 m^3
Play Area:						
1. Foothills (e.g. Findlay Field)	0.95	2.68	2.50	2.14	7.32	8.27
2. Phosphatic Limestones – West-Central Alberta (e.g. Pine Creek Field)	8.08	7.66	1.75	19.15	28.56	36.62
3. Shoreface Deposits – Central Alberta (e.g. Cherhill Field)	56.58	11.83	1.94	16.83	30.60	87.18
4. Shoreface Deposits – Peace River Arch	0.47	0.00	0.00	1.87	1.87	2.34
Play Area Totals	66.08	22.17	6.19	39.99	68.36	134.41

BALDONNEL AND CHARLIE LAKE INTERVAL

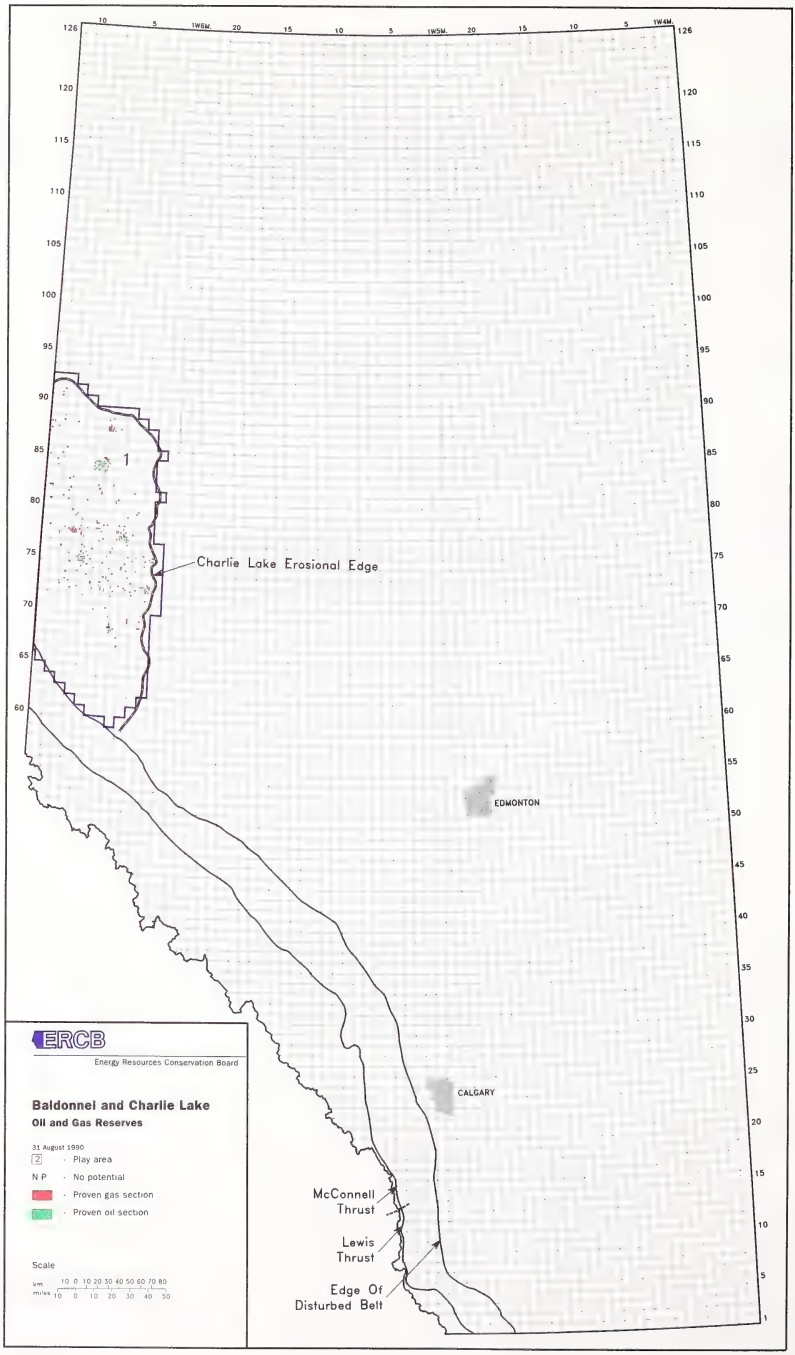

1W6M
1W5M
1W4M
Charlie Lake Erosional Edge
EDMONTON
CALGARY
McConnell Thrust
Lewis Thrust
Edge Of Disturbed Belt
ERCB
Energy Resources Conservation Board
Baldonnel and Charlie Lake
Oil and Gas Reserves
31 August 1990
Play area
N P · No potential
Proven gas section
Proven oil section
Scale
km
miles

FIGURE 20

D.20 Baldonnel and Charlie Lake Interval

Reservoir Parameters:

Maximum Pay Thickness	6 metres
Porosity Range	4 to 25%
Pool Size Range	< 1 to 16 sections
Gas Saturation Range	25 to 90%
Recovery Factor Range	46 to 85%

Number of Play Areas = 1

Play Area 1: Sabkha Deposits — Northwestern Alberta
(e.g. Wembley Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	1	1	606	7	75
	Assoc.	3	3	626	7	44 - 78
	Sol'n	5	5	603	7	4 - 19
Two or less	Non-Assoc.	78	77	5 768	69	8 - 254
	Assoc.	7	7	691	8	7 - 134
	Sol'n	7	7	121	1	7 - 32

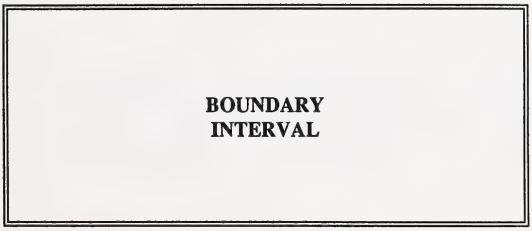
Play Area 1 is defined by the depositional and erosional limits of the Charlie Lake Formation in northwestern Alberta. The Charlie Lake Formation has a number of dolomite members that could contain stratigraphic traps in localized areas. The Baldonnel Formation, which is confined to a smaller area within this play, contains extensively leached bioclastic sediments that were subsequently dolomitized to form present-day reservoirs in fields such as Pouce Coupe South. The subcrop edge for the Charlie Lake and Baldonnel Formations is poorly delineated with present drilling. Pre-Jurassic erosion may have enhanced reservoir quality, and therefore this area may contain subtle hydrocarbon traps.

In the deeper portions of the Deep Basin, gas entrapment does not occur because of the extreme depth of burial. In the northern part of the play area, the formations rapidly shale out due to influences of the Peace River Arch.

Additional gas is expected from both pool expansion and new pools. The undiscovered potential for this play area is estimated at 31.62×10^9 m^3 (1123 Bcf), with estimates of the undiscovered pool size ranging up to three sections.

Ultimate Gas In Place

Baldonnel and Charlie Lake Interval	Initial Gas In Place	Undiscovered 10^9 m^3				Ultimate Gas In Place
	10^9 m^3	GRC 1	GRC 2	GRC 3	Total	10^9 m^3
Play Area:						
1. Sabkha Deposits – Northwestern Alberta (e.g. Wembley Field)	8.42	12.72	2.97	15.93	31.62	40.04
Play Area Totals	8.42	12.72	2.97	15.93	31.62	40.04


BOUNDARY
INTERVAL

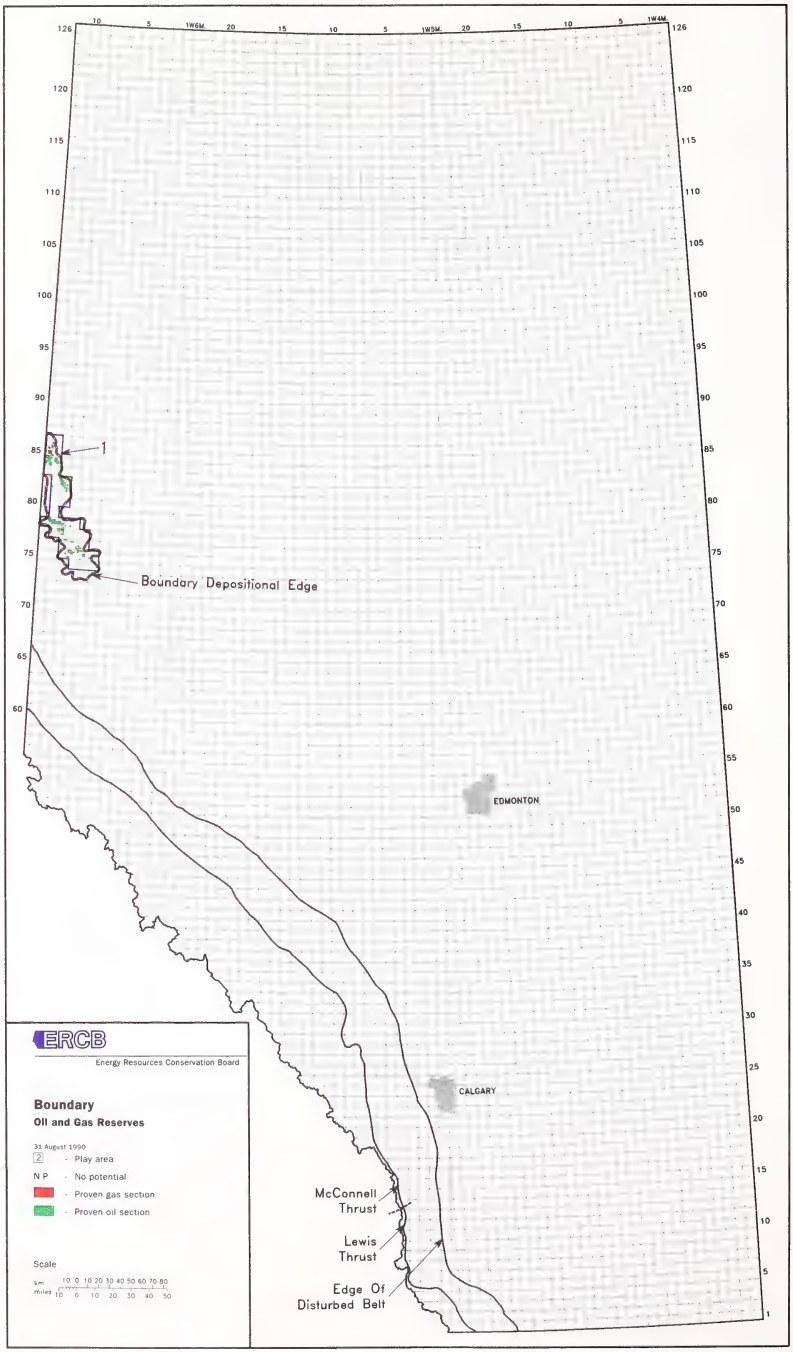

1
Boundary Depositional Edge
EDMONTON
CALGARY
McConnell Thrust
Lewis Thrust
Edge Of Disturbed Belt
ERCB
Energy Resources Conservation Board
Boundary
Oil and Gas Reserves
31 August 1990
2 - Play area
N P - No potential
- Proven gas section
- Proven oil section
Scale
km 10 0 10 20 30 40 50 60 70 80
miles 10 0 10 20 30 40 50

FIGURE 21

D.21 Boundary Interval

Reservoir Parameters:

Maximum Pay Thickness	7 metres
Porosity Range	5 to 25%
Pool Size Range	< 1 to 17 sections
Gas Saturation Range	45 to 90%
Recovery Factor Range	36 to 90%

Number of Play Areas = 1.

Play Area 1: Tidal Flat to Lagoonal Deposits – Northwestern Alberta
(e.g. Boundary Lake South Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	-	-	-	-	-
	Assoc.	-	-	-	-	-
	Sol'n	5	50	2 282	85	7 - 32
Two or less	Non-Assoc.	2	20	260	10	35 - 231
	Assoc.	3	30	128	5	39 - 46
	Sol'n	-	-	-	-	-

Play Area 1 consists of tidal flat and lagoonal limestones and dolomites of the Boundary Member in northwestern Alberta. The Boundary play also extends into northeastern British Columbia.

Most of the proven gas to date is solution gas, while the undiscovered gas potential is expected from associated and non-associated gas pools. Additional gas is expected from both expansion of existing single-well pools and discovery of new pools. The undiscovered potential for this play area is estimated at 4.83×10^9 m^3 (171 Bcf), with estimates of the undiscovered pool size ranging up to 1.5 sections.

Ultimate Gas In Place

Boundary Interval	Initial Gas In Place	Undiscovered 10^9 m^3				Ultimate Gas In Place
	10^9 m^3	GRC 1	GRC 2	GRC 3	Total	10^9 m^3
Play Area: 1. Tidal Flat to Lagoonal Deposits – Northwestern Alberta (e.g. Boundary Lake South Field)	2.67	2.36	1.36	1.11	4.83	7.50
Play Area Totals	2.67	2.36	1.36	1.11	4.83	7.50

HALFWAY
INTERVAL

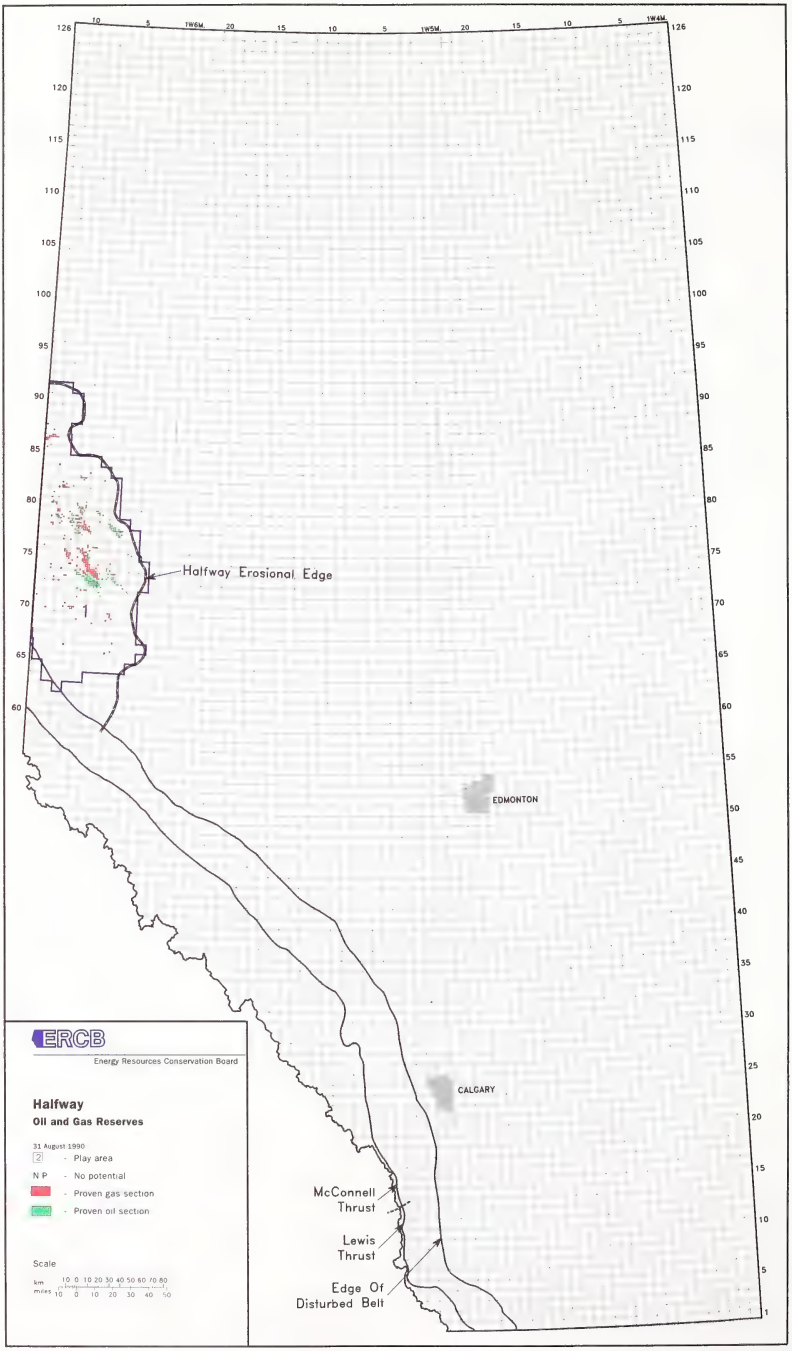

Halfway Erosional Edge
EDMONTON
CALGARY
McConnell Thrust
Lewis Thrust
Edge Of Disturbed Belt
ERCB
Energy Resources Conservation Board
Halfway
Oil and Gas Reserves
31 August 1990
Play area
N P - No potential
Proven gas section
Proven oil section
Scale
km
miles

FIGURE 22

D.22 Halfway Interval

Reservoir Parameters:

Maximum Pay Thickness	15 metres
Porosity Range	5 to 25%
Pool Size Range	< 1 to 60 sections
Gas Saturation Range	40 to 90%
Recovery Factor Range	36 to 90%

Number of Play Areas = 1

Play Area 1: Shoreface and Barrier Island Deposits – Northwestern Alberta
(e.g. Wembley Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	8	7	8 223	21	76 - 221
	Assoc.	4	4	12 831	33	62 - 217
	Sol'n	6	5	6 486	17	11 - 70
Two or less	Non-Assoc.	78	70	9 453	24	6 - 354
	Assoc.	10	9	1 360	4	19 - 293
	Sol'n	5	5	269	1	23 - 83

Play Area 1 is defined by longshore bar, barrier island and tidal channel deposits consisting of sand, silt and coquina. Limited potential was assigned to areas of Halfway drape over fault structures and along the erosional edge. The trapping mechanism is both structural and stratigraphic with lateral seals being finer grained sandstones and siltstones.

Post-depositional tectonic activity on the Peace River Arch, expressed by faulting into the Triassic, and differential compaction of underlying sediments, is interpreted to be a factor in Halfway drape trap development along the erosional edge.

Back from the erosional edge, Peace River Arch tectonic effects are minimal and existing traps are caused by diagenetic and facies changes within the continuous bar and barrier sandstones. Minor subtle traps are predicted to drape block faults of the Peace River Arch. Additional gas is expected from new pools.

The undiscovered potential for this play area is estimated at 61.80×10^9 m^3 (2194 Bcf), with estimates of the undiscovered pool size ranging up to seven sections.

Ultimate Gas In Place

Halfway Interval	Initial Gas In Place	Undiscovered 10^9 m^3				Ultimate Gas In Place
	10^9 m^3	GRC 1	GRC 2	GRC 3	Total	10^9 m^3
Play Area: 1. Shoreface and Barrier Island Deposits – Northwestern Alberta (e.g. Wembley Field)	38.62	18.63	7.65	35.52	61.80	100.42
Play Area Totals	38.62	18.63	7.65	35.52	61.80	100.42

DOIG AND MONTNEY INTERVAL

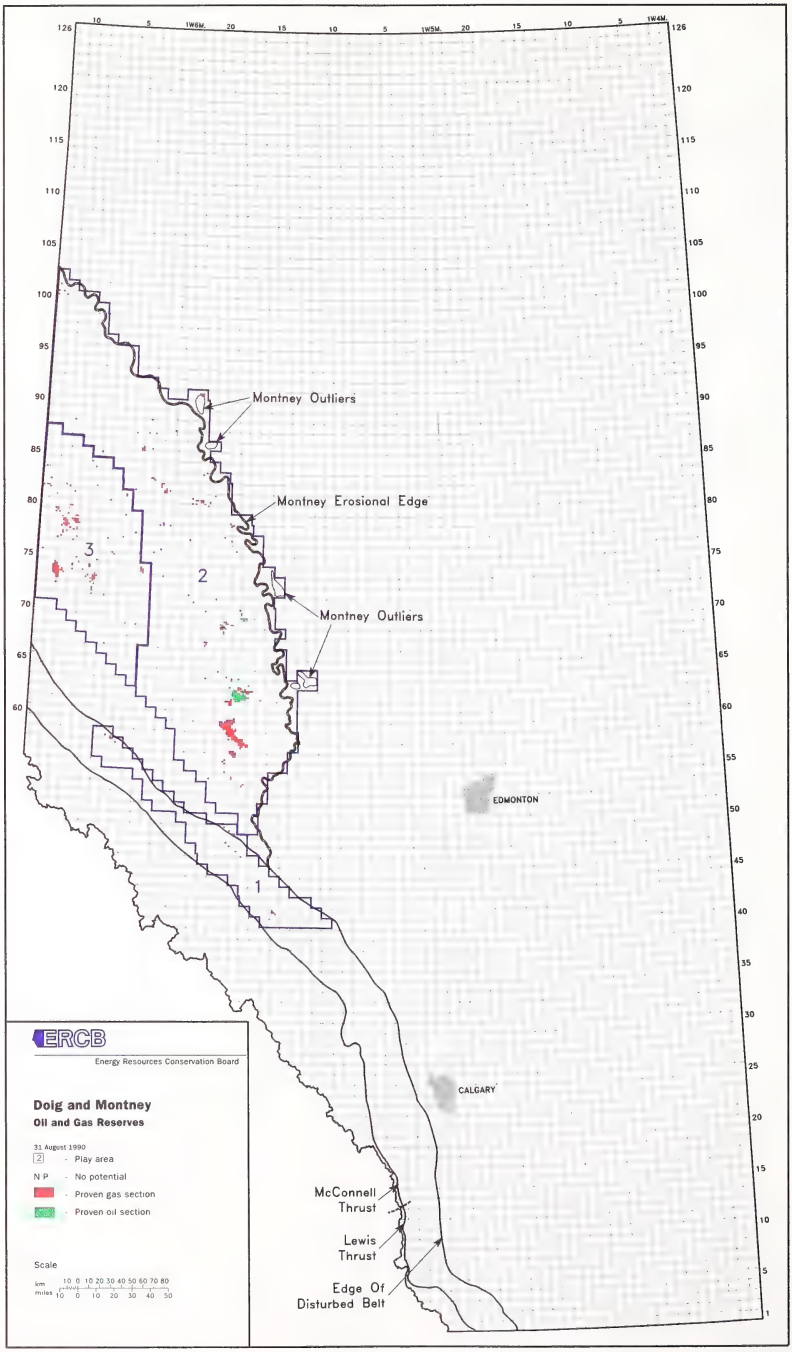

Montney Outliers
Montney Erosional Edge
Montney Outliers
3
2
1
EDMONTON
CALGARY
McConnell Thrust
Lewis Thrust
Edge Of Disturbed Belt
ERCB
Energy Resources Conservation Board
Doig and Montney
Oil and Gas Reserves
31 August 1990
2 - Play area
N P - No potential
- Proven gas section
- Proven oil section
Scale
km 10 0 10 20 30 40 50 60 70 80
miles 10 0 10 20 30 40 50

FIGURE 23

D.23 Doig and Montney Interval

Reservoir Parameters:

Maximum Pay Thickness	39 metres
Porosity Range	3 to 27%
Pool Size Range	< 1 to 90 sections
Gas Saturation Range	40 to 90%
Recovery Factor Range	33 to 90%

Number of Play Areas = 3

Play Area 1: Foothills
(e.g. Basing Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	4	31	1 249	34	11 - 112
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	9	69	2 461	66	52 - 1 027
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-

Play Area 1 consists of productive Triassic reservoirs in the foothills confined to the area between townships 40 and 58. The reservoir rock is dolomitized coquina sandstones, probably equivalent to the Montney reservoirs in the Sturgeon Lake and Kaybob South Fields. Structural closure for the Triassic is related to underlying Mississippian structure. Therefore, this zone is considered to be a secondary target. Potential was determined using the same method as for the Cadomin in Play Area 1.

The undiscovered potential for this play area is estimated at 4.34×10^9 m^3 (154 Bcf), with estimates of the pool size ranging up to four sections.

Play Area 2: Montney — Shoreline and Dolomitized Coquina Deposits — Northwestern Alberta
(e.g. Kaybob South Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	9	10	15 176	56	11 - 245
	Assoc.	5	6	2 066	8	20 - 157
	Sol'n	3	3	4 902	18	13 - 69
Two or less	Non-Assoc.	73	79	4 935	18	1 - 219
	Assoc.	2	2	51	<1	16 - 35
	Sol'n	-	-	-	-	-

Play Area 2 is characterized by shoreline and dolomitized coquina deposits in the Montney Formation. It is limited to the east where Montney Formation progrades onto the shore. Producing reservoirs include those in the Sturgeon and Kaybob South Fields which exhibit leached coquinas with moldic porosity. North of these fields, the dolostones and coquinas show some primary and secondary vuggy porosity and may also be potential reservoirs (Gibson and Barclay, 1989).

Additional gas is expected from the discovery of new pools. The undiscovered potential for this play area is estimated at 49.04×10^9 m^3 (1741 Bcf), with estimates of the undiscovered pool size ranging up to 92 sections.

Play Area 3: Doig — Tidal, Channel and Coquina Deposits — Northwestern Alberta
(e.g. Sinclair Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	4	8	19 319	72	96 - 493
	Assoc.	1	2	1 691	6	187
	Sol'n	2	4	878	3	50 - 140
Two or less	Non-Assoc.	38	78	4 161	16	17 - 515
	Assoc.	3	6	634	2	18 - 455
	Sol'n	1	2	10	<1	10

In Play Area 3, the Upper Doig Formation is characterized by regressive sediments deposited within complexes of "tidal and estuarine channels, barrier islands, tidal flats and near shore shelf settings" (Gibson and Barclay, 1989). The play area is confined to the western portion of the basin in the Peace River Arch area and limited by the Doig Formation depositional limits. In most areas of this play, Doig strata display coarsening upward profiles on well logs and represent an overall regressive character. The southern portion of the play area has no potential since Doig sediments occur below the regional hot line.

Additional gas is expected from discovery of new pools in the Upper Doig. The undiscovered potential for this play area is estimated at 28.86 $\times$ 10^9 m^3 (1025 Bcf), with estimates of the undiscovered pool size ranging up to eight sections.

Ultimate Gas In Place

Doig and Montney Interval	Initial Gas In Place	Undiscovered 10^9 m^3				Ultimate Gas In Place
	10^9 m^3	GRC 1	GRC 2	GRC 3	Total	10^9 m^3
Play Area:						
1. Foothills (e.g. Basing Field)	3.71	0.72	0.49	3.13	4.34	8.05
2. Montney – Shoreline and Dolomitized Coquina Deposits – Northwestern Alberta (e.g. Kaybob South Field)	27.13	10.98	5.26	32.80	49.04	76.17
3. Doig – Tidal, Channel and Coquina Deposits – Northwestern Alberta (e.g. Sinclair Field)	26.69	9.77	2.98	16.11	28.86	55.55
Play Area Totals	57.53	21.47	8.73	52.04	82.24	139.77

BELLOY, KISKATINAW, AND TAYLOR FLAT INTERVAL

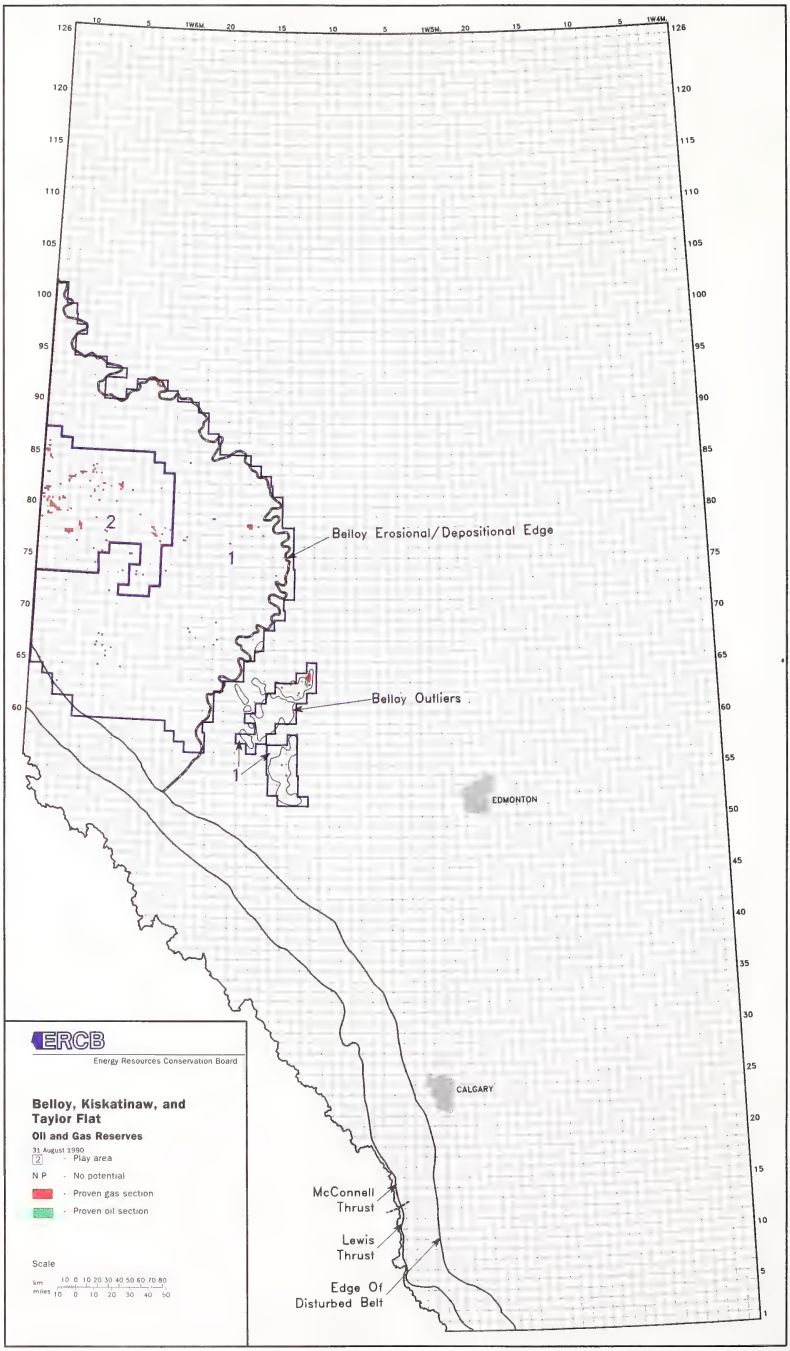

Belloy Erosional/Depositional Edge
Belloy Outliers
EDMONTON
CALGARY
McConnell Thrust
Lewis Thrust
Edge Of Disturbed Belt
ERCB
Energy Resources Conservation Board
Belloy, Kiskatinaw, and Taylor Flat
Oil and Gas Reserves
31 August 1990
2 - Play area
N P - No potential
- Proven gas section
- Proven oil section
Scale
km 10 0 10 20 30 40 50 60 70 80
miles 10 0 10 20 30 40 50

FIGURE 24

D.24 Belloy, Kiskatinaw and Taylor Flat Interval

Reservoir Parameters:

Belloy:

Maximum Pay Thickness	22 metres
Porosity Range	5 to 30%
Pool Size Range	<1 to 11 sections
Gas Saturation Range	50 to 85%
Recovery Factor Range	15 to 92%

Kiskatinaw and Taylor Flat:

Maximum Pay Thickness	22 metres
Porosity Range	4 to 25%
Pool Size Range	<1 to 10 sections
Gas Saturation Range	45 to 90%
Recovery Factor Range	50 to 95%

Number of Play Areas = 2

Play Area 1: Belloy – Bar Deposits – Northwestern Alberta
(e.g. Virginia Hills Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	2	5	740	8	13 - 68
	Assoc.	1	2	1 278	13	116
	Sol'n	1	2	632	6	45
Two or less	Non-Assoc.	36	86	6 817	70	3 - 729
	Assoc.	2	5	315	3	66 - 249
	Sol'n	-	-	-	-	-

Play Area 1 is characterized by both carbonate and sandstone units. It is bounded by the depositional and erosional limits of the Belloy Formation and the downdip hot line to the southwest. To date reservoirs are confined to the clastic portion, mostly around the subcrop. However, porosity and permeability appear to be widespread throughout much of the play area. Elusive downdip trapping mechanisms, associated with fluid movement along pre-existing fault planes, may provide potential for hydrocarbon entrapment in the Belloy around the Peace River Arch.

Additional gas is expected primarily from new pools. The undiscovered potential for this play area is estimated at 24.50 $\times$ 10^9 m^3 (870 Bcf), with estimates of the undiscovered pool size ranging up to four sections.

Play Area 2: Kiskatinaw and Taylor Flat — Marine Deposits — Northwestern Alberta
(e.g. Pouce Coupe Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	12	13	8 050	36	28 - 236
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	81	85	14 157	64	11 - 1 160
	Assoc.	-	-	-	-	-
	Sol'n	2	2	13	<1	5 - 8

Play Area 2 consists of clastics of the Kiskatinaw Formation and bioclastic carbonates of the Taylor Flat Formation. The play area is bounded by the limits of the Peace River embayment as it existed in Mississippian time. Graben complexes associated with the Peace River Arch tectonics have increased the complexity of the trapping mechanisms which are both structural and stratigraphic. Potential may be encountered in more than one zone in this play area.

Additional gas is expected from the discovery of new pools. The undiscovered potential for this play area is estimated at 28.72 $\times$ 10^9 m^3 (1020 Bcf), with estimates of the undiscovered pool size ranging up to four sections.

Ultimate Gas In Place

Belloy, Kiskatinaw and Taylor Flat Interval	Initial Gas In Place	Undiscovered 10^9 m^3				Ultimate Gas In Place
	10^9 m^3	GRC 1	GRC 2	GRC 3	Total	10^9 m^3
Play Area:						
1. Belloy – Bar Deposits – Northwestern Alberta (e.g. Virginia Hills Field)	9.78	7.28	1.46	15.76	24.50	34.28
2. Kiskatinaw and Taylor Flat – Marine Deposits – Northwestern Alberta (e.g. Pouce Coupe Field)	22.22	8.64	1.92	18.16	28.72	50.94
Play Area Totals	32.00	15.92	3.38	33.92	53.22	85.22

TURNER VALLEY
INTERVAL

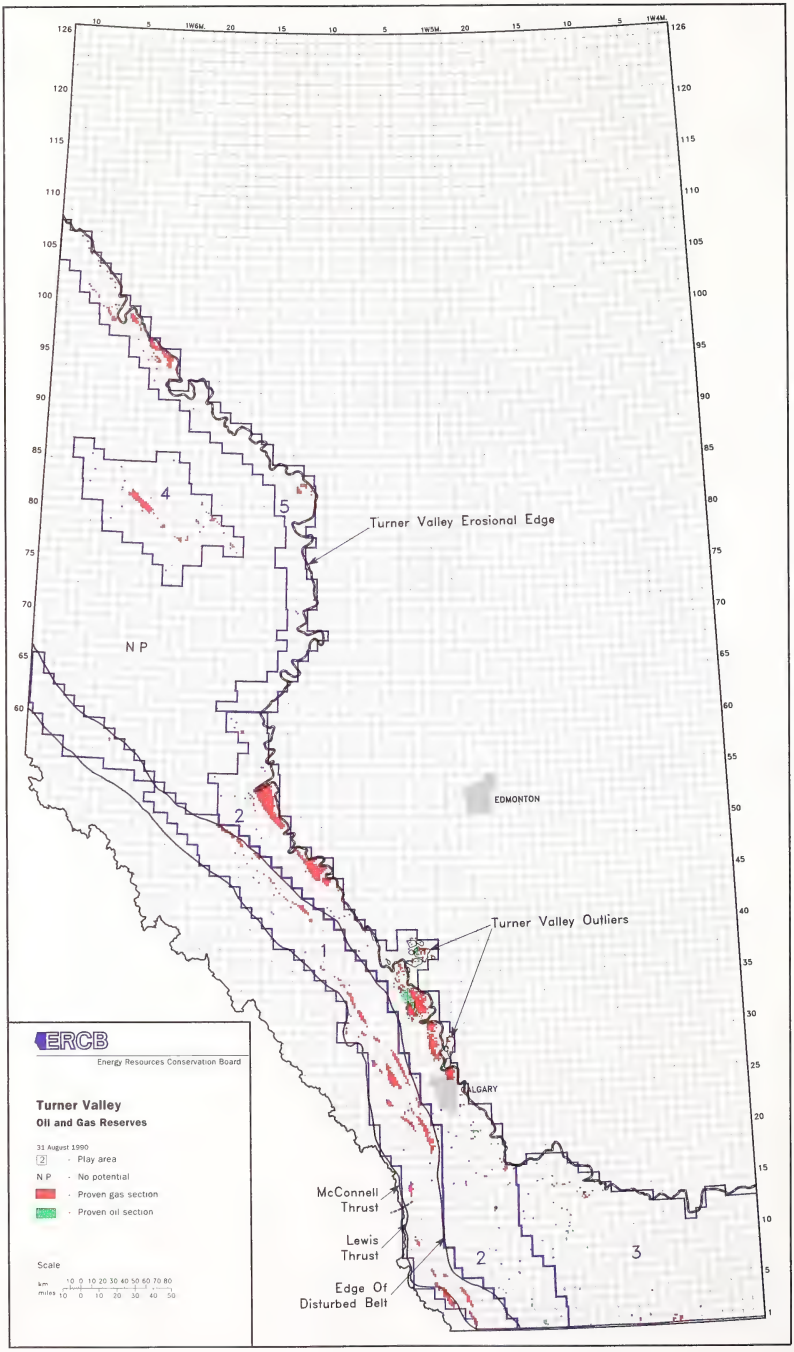

Turner Valley Erosional Edge
Turner Valley Outliers
EDMONTON
CALGARY
McConnell Thrust
Lewis Thrust
Edge Of Disturbed Belt
NP
1
2
3
4
5
ERCB
Energy Resources Conservation Board
Turner Valley
Oil and Gas Reserves
31 August 1990
2 - Play area
N P - No potential
- Proven gas section
- Proven oil section
Scale
km
miles

FIGURE 25

D.25 Turner Valley Interval

Reservoir Parameters:

Maximum Pay Thickness	173 metres
Porosity Range	3 to 27%
Pool Size Range	<1 to 181 sections
Gas Saturation Range	20 to 90%
Recovery Factor Range	16 to 95%

For Play Area 1 of the Turner Valley Formation, the lack of access to seismic data limits making predictions regarding potential structures along the proven structural trends. Also, based on the absence of drilling to date, no potential was assigned between the known trends.

The reserves discovered to date indicate that there are main structural trends that exist in the foothills region (e.g. Limestone to Ram Fields). In GRC 1, minor reserve additions are expected as a result of extensions to existing pools. This is based on the ERCB's current mapped data which are based on log evaluations and material balance information, and supported by data submitted by industry on seismic interpretations of fault traces, pressure derived free water levels and transitional zones. There are a number of single-section pools that are not yet fully delineated and reserve extensions to these pools would account for most of the undiscovered gas volume for GRC 1.

Wells that were evaluated as having possible or proven gas were used to estimate the ratio of existing structures per area. This ratio was then applied to remaining areas on trend to predict the potential for new structures in GRCs 2 and 3.

Finally, potential has only been assigned to non-associated gas as the ERCB oil supply study (ERCB Report 88-E) concluded that no oil potential exists in the foothills for this zone or any of the Paleozoic zones.

Number of Play Areas = 5

Play Area 1: **Foothills**
(e.g. Limestone Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	44	41	420 630	77	9 - 3 614
	Assoc.	1	1	42 063	8	824
	Sol'n	1	1	38 429	7	349
Two or less	Non-Assoc.	56	52	37 041	7	3 - 2 651
	Assoc.	4	4	565	< 1	42 - 263
	Sol'n	1	1	52	< 1	52

Play Area 1 is characterized by reservoir development in three stratigraphic units within the foothills: 1) Mt Head, 2) Turner Valley or 3) Livingstone. The Turner Valley is the most important horizon with the Mt Head and Livingstone contributing minor reserves. Structural traps form on culminations at the Mississippian level where formations are: 1) displaced upwards to the northeast on low angle reverse faults, 2) folded into concentric folds, 3) displaced due to tear faults, and 4) displaced due to late normal faults (Dahlstrom, 1970). The resulting configuration is usually elliptical shaped doubly plunging anticlines. Structural complexities can cause pool separation within the overall trap, however multiple repeats of reservoir units also result. Additional gas is expected from new pools in deeper structures whose overall size will be smaller than the mean pool size for this play area.

The undiscovered potential for this play area is estimated at 240.87×10^9 m^3 (8550 Bcf), with estimates of the undiscovered pool size ranging up to 12 sections.

Play Area 2: Elkton Subcrop – Central and Southern Alberta
(e.g. Brazeau River Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	16	12	185 535	63	10 - 1 238
	Assoc.	6	5	71 295	25	18 - 921
	Sol'n	9	7	17 061	6	10 - 152
Two or less	Non-Assoc.	76	58	17 356	6	11 - 859
	Assoc.	11	8	698	<1	3 - 261
	Sol'n	13	10	935	<1	2 - 154

Play Area 2 consists of the area where gas is trapped in the dolomitized carbonates of the Elkton Member. The limits of the play area are defined by the Elkton depositional limit and its erosional edge. Most of the proven pools occur where gas has been trapped near the erosional edge. Although extensively drilled, there are still many undrilled sections adjacent to smaller pools. The southern part of the play area, where the Elkton exists downdip from its subcrop edge, could contain stratigraphic traps in dolomitized shelf margin facies.

Additional gas is expected primarily from the discovery of new pools. The undiscovered potential for this play area is estimated at 119.74×10^9 m^3 (4251 Bcf), with estimates of the undiscovered pool size ranging up to seven sections.

Play Area 3: Livingstone Subcrop – Southern Alberta
(e.g. Enchant Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	3	15	2 164	68	20 - 319
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	15	75	958	30	6 - 249
	Assoc.	2	10	38	1	9 - 29
	Sol'n	-	-	-	-	-

Play Area 3 is characterized by crinoidal limestones with lesser amounts of dolomitic limestone interbeds. It is limited by the Livingstone Formation depositional limit and erosional edge. Most of the reserves are distributed in non-associated gas pools adjacent to the erosional edge. Such pools result from secondary porosity development which results from erosion and subaerial exposure and appear to represent the best reservoir potential. Some potential also exists downdip from the erosional edge.

The undiscovered gas is expected primarily in new pools. The undiscovered potential for this play area is estimated at 4.73×10^9 m^3 (168 Bcf), with estimates of the undiscovered pool size ranging up to three sections.

Play area 4: **Debolt – Peace River Arch**
(e.g. Dunvegan Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	13	18	39 810	85	26 - 358
	Assoc.	1	1	362	1	90
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	57	78	6 256	13	3 - 359
	Assoc.	2	3	152	<1	38 - 114
	Sol'n	-	-	-	-	-

Play Area 4 is characterized by mainly limestone and dolomite with some anhydrite. The play area consists of that area where the Debolt Formation has been displaced as a result of basement faults. The Debolt in this area can be separated into four units with most of the reserves in the upper units. The potential exists where basement faults have resulted in sufficient structure at the Debolt level to trap hydrocarbons. Large horst features would represent the most attractive plays.

Additional gas is expected primarily from the discovery of new pools. The undiscovered potential for this play area is estimated at 32.39×10^9 m^3 (1150 Bcf), with estimates of the undiscovered pool size ranging up to five sections.

Play Area 5: Debolt Subcrop – Central and Northern Alberta
(e.g. Hotchkiss Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	11	29	10 165	90	15 - 78
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	27	71	1 195	10	3 - 146
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-

Play Area 5 is limited by the Debolt Formation erosional edge and the transition into Elkton Member sediments. Reservoir development has occurred primarily near the edge. However, much of the subcrop is undrilled, especially the area adjacent to many of the single and two section pools. High residual oil saturations due to bitumen plugging has reduced the initial GIP values compared to other play areas which will also affect future discoveries.

Additional gas is expected from both pool expansion and the discovery of new pools. The undiscovered potential for this play area is estimated at 13.83×10^9 m^3 (491 Bcf), with estimates of the undiscovered pool size ranging up to six sections.

Ultimate Gas In Place

Turner Valley Interval	Initial Gas In Place	Undiscovered 10^9 m^3				Ultimate Gas In Place
	10^9 m^3	GRC 1	GRC 2	GRC 3	Total	10^9 m^3
Play Area:						
1. Foothills (e.g. Limestone Field)	538.78	62.56	40.03	138.28	240.87	779.65
2. Elkton Subcrop – Central and Southern Alberta (e.g. Brazeau River Field)	292.88	23.25	3.84	92.65	119.74	412.62
3. Livingstone Subcrop – Southern Alberta (e.g. Enchant Field)	3.16	1.13	0.46	3.14	4.73	7.89
4. Debolt – Peace River Arch (e.g. Enchant Field)	46.58	3.59	2.73	26.07	32.39	78.97
5. Debolt Subcrop – Central and Northern Alberta (e.g. Hotchkiss Field)	11.36	2.98	0.91	9.94	13.83	25.19
Play Area Totals	892.76	93.51	47.97	270.08	411.56	1 904.32

SHUNDA
INTERVAL

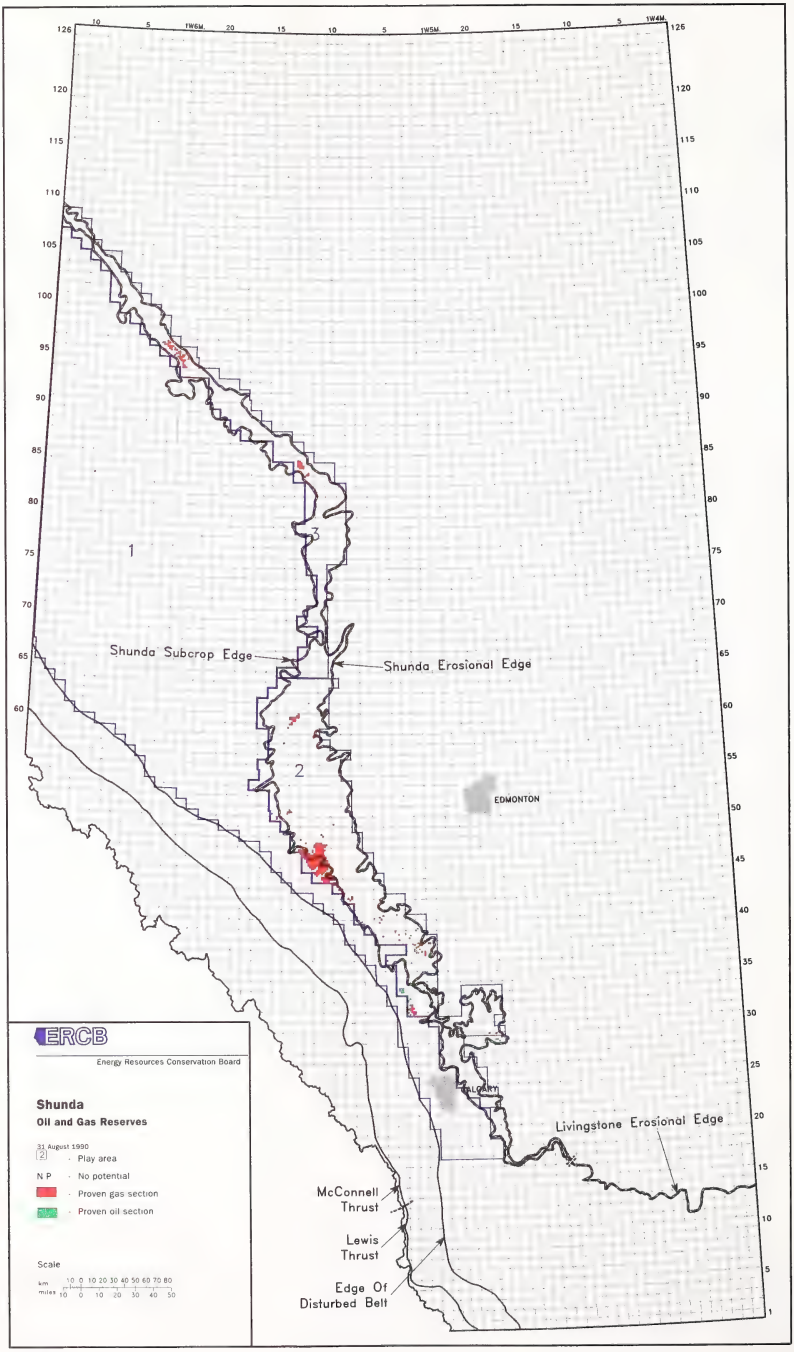

Shunda Subcrop Edge
Shunda Erosional Edge
EDMONTON
CALGARY
Livingstone Erosional Edge
McConnell Thrust
Lewis Thrust
Edge Of Disturbed Belt
1
2
3
ERCB
Energy Resources Conservation Board
Shunda
Oil and Gas Reserves
31 August 1990
Play area
N P · No potential
Proven gas section
Proven oil section
Scale

FIGURE 26

D.26 Shunda Interval

Reservoir Parameters:

Maximum Pay Thickness	18 metres
Porosity Range	3 to 21%
Pool Size Range	< 1 to 165 sections (5 TWPs)
Gas Saturation Range	15 to 90%
Recovery Factor Range	50 to 92%

Number of Play Areas = 3

Play Area 1: Platform Deposits Backstepping Subcrop – Western Alberta

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	-	-	-	-	-
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	1	100	155	100	155
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-

The Shunda Formation in central and southern Alberta is characterized by interbedded carbonate and shales. Play Area 1 is limited to Shunda downdip of the subcrop edge. It is further limited by the eastern edge of the Disturbed Belt and, in the south, by the transition into the Livingstone Formation. To date, only minimal proven gas has been discovered, and that as a result of drilling for a deeper target. Therefore, potential is assigned only to GRC 3.

The undiscovered potential for this play area is estimated at 1.71×10^9 m^3 (61 Bcf), with estimates of the undiscovered pool size ranging up to two sections.

Play Area 2: Subcrop — South-Central Alberta
(e.g. Brazeau River Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	10	19	29 112	88	8 - 383
	Assoc.	-	-	-	-	-
	Sol'n	2	4	391	1	51 - 59
Two or less	Non-Assoc.	39	72	3 340	10	4 - 384
	Assoc.	2	4	256	1	8 - 124
	Sol'n	1	2	71	<1	71

Play Area 2 consists of interbedded carbonate and shales of the Shunda Formation subcrop, between the Turner Valley and Shunda erosional edges. The northern boundary occurs at a facies transition to siliciclastic sediments. Post-depositional processes in the play area have resulted in hydrocarbon accumulations in thin pay zones and small pool sizes.

Additional gas is expected from pool expansion of the many single-well pools and discovery of new pools. The undiscovered potential for this play area is estimated at 22.27×10^9 m^3 (791 Bcf), with estimates of the undiscovered pool size ranging up to four sections.

Play Area 3: Subcrop — North-Central Alberta
(e.g. Hotchkiss Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	2	25	339	64	17 - 19
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	6	75	191	36	15 - 53
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-

Play Area 3 is the northern continuation of the subcrop play, where the Shunda Formation undergoes a facies change to a shallow-shelf siliciclastic unit. Complex post-depositional processes have reduced

much of the primary porosity resulting in sporadic accumulations in thin pay zones. As with the Debolt in the northern subcrop, the Shunda also contains high residual oil saturations resulting in lower average IGIP values than other play areas.

Additional gas is expected from both expansion and step-out of existing pools and discovery of new pools. The undiscovered potential for this play area is estimated at 4.81 $\times$ 10^9 m^3 (171 Bcf) with estimates of the undiscovered pool size ranging up to two sections.

Ultimate Gas In Place

Shunda Interval	Initial Gas In Place	Undiscovered 10^9 m^3				Ultimate Gas In Place
	10^9 m^3	GRC 1	GRC 2	GRC 3	Total	10^9 m^3
Play Area:						
1. Platform Deposits Backstepping Subcrop – Western Alberta	0.16	0.00	0.00	1.71	1.71	1.87
2. Subcrop – South-Central Alberta (e.g. Brazeau River Field)	33.17	9.12	1.90	11.25	22.27	55.44
3. Subcrop – North-Central Alberta (e.g. Hotchkiss Field)	0.53	2.59	0.44	1.78	4.81	5.34
Play Area Totals	33.86	11.71	2.34	14.74	28.79	62.65

PEKISKO
INTERVAL

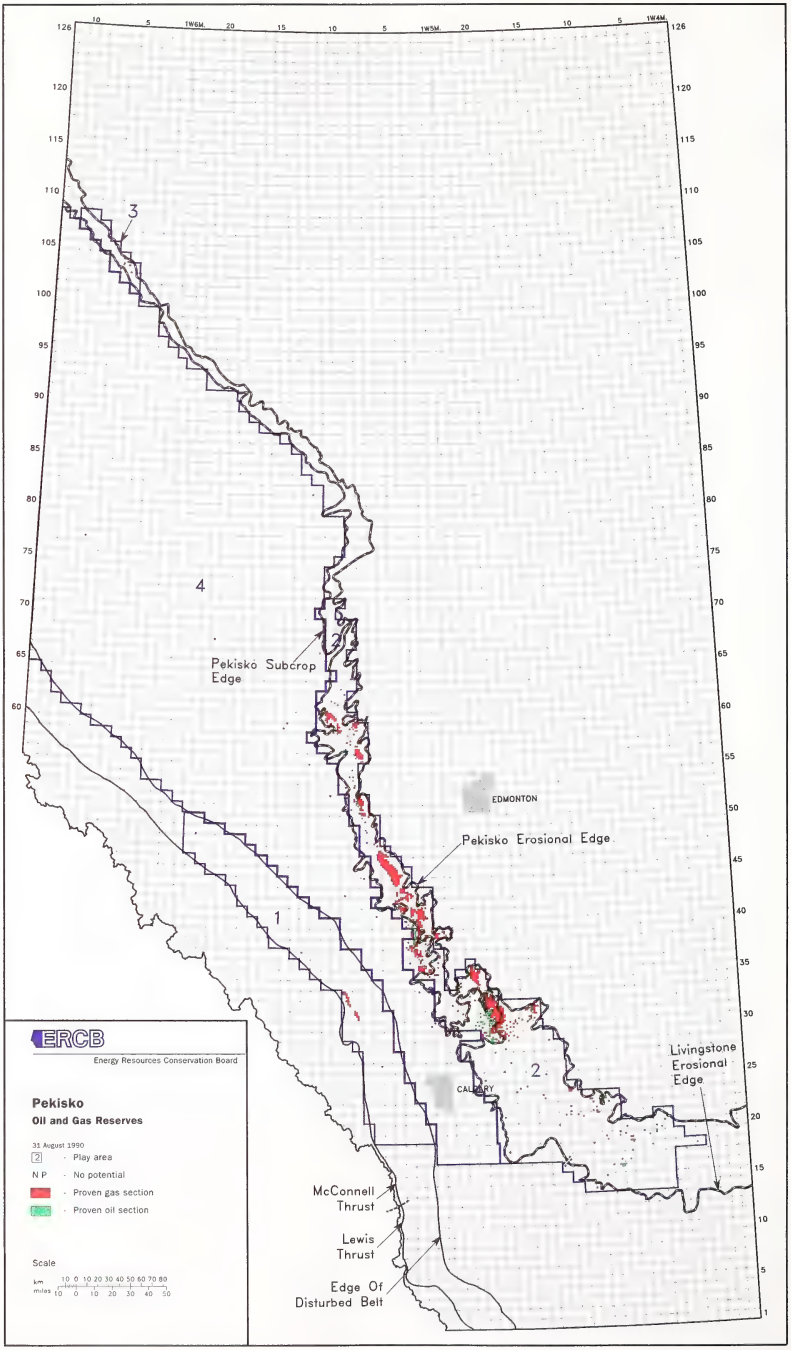

ERCB
Energy Resources Conservation Board
Pekisko
Oil and Gas Reserves
31 August 1990
2 - Play area
N P - No potential
- Proven gas section
- Proven oil section
Scale
km 10 0 10 20 30 40 50 60 70 80
miles 10 0 10 20 30 40 50
3
4
1
2
Pekisko Subcrop Edge
Pekisko Erosional Edge
EDMONTON
CALGARY
Livingstone Erosional Edge
McConnell Thrust
Lewis Thrust
Edge Of Disturbed Belt

FIGURE 27

D.27 Pekisko Interval

Reservoir Parameters:

Maximum Pay Thickness	30 metres
Porosity Range	3 to 24%
Pool Size Range	< 1 to 168 sections (5 TWPs)
Gas Saturation Range	30 to 90%
Recovery Factor Range	20 to 92%

Number of Play Areas = 4

Play Area 1: Foothills
(e.g. Limestone Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	3	50	4 706	76	120 - 276
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	3	50	1 476	24	299 - 702
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-

In Play Area 1, the Pekisko Formation is characterized by folded and faulted crinoidal limestones. The play area is defined by the edge of the Disturbed Belt in the east, the McConnell and Lewis Thrusts to the west and to the south by the nomenclature change to the Livingstone Formation. The northern limit of the foothills play is arbitrarily based on the lack of reserves to date north of township 48. The recent discovery in the Ram Field (038-15W5) continues to substantiate the potential for this zone.

Potential was determined using the same method as for the Turner Valley Play Area 1. It is expected that additional gas will primarily be discovered in new pools. The undiscovered potential for this play area is estimated at 22.25×10^9 m^3 (790 Bcf), with estimates of the undiscovered pool size ranging up to five sections.

Play Area 2: Subcrop — South-Central Alberta
(e.g. Twining Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	22	10	46 375	40	3 - 416
	Assoc.	16	7	44 205	38	16 - 377
	Sol'n	22	10	12 068	10	1 - 96
Two or less	Non-Assoc.	110	51	11 991	10	1 - 452
	Assoc.	23	11	945	1	2 - 118
	Sol'n	21	10	786	1	5 - 132

Play Area 2 is characterized by crinoidal limestones affected by post-depositional diagenetic processes. The play area is limited to the Pekisko subcrop in central Alberta. Pools in this play area have typically been discovered in the 1960s and 1970s as a result of exploration for deeper targets. Traps are formed by Mesozoic shale filled channels surrounding Pekisko remnants, Mesozoic marine shales capping the main Pekisko erosional surface or with dense Shunda Formation as the top seal (Podruski et al, 1987).

Additional gas is expected from both the expansion of existing pools and discovery of new pools. The undiscovered potential for this play area is estimated at 41.00×10^9 m^3 (1456 Bcf), with estimates of the undiscovered pool size ranging up to four sections.

Play Area 3: Subcrop — North-Central Alberta
(e.g. Haro Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	-	-	-	-	-
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	5	100	288	100	11 - 210
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-

Play Area 3 is the northern continuation of the subcrop play, where the Pekisko Formation undergoes a facies change to a more argillaceous carbonate unit in the area of townships 75 to 100. This facies change resulted from an embayment during Pekisko time. Where this embayment occurred, it is observed that the basal carbonate unit can be plugged with bitumen. North of the embayment, the Pekisko is a small outlier of poorly developed carbonate encased in shales.

As with the Debolt in the northern subcrop, the Pekisko also contains high residual oil saturations resulting in lower average IGIP values than for other play areas.

Additional gas is expected from both expansion and new pool discoveries. The undiscovered potential for this play area is estimated at 3.05×10^9 m^3 (108 Bcf), with estimates of the undiscovered pool size ranging up to three sections.

Play Area 4: Platform Deposits Backstepping Subcrop – Western Alberta

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	-	-	-	-	-
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	9	100	1 779	100	31 - 501
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-

Play Area 4 is the remaining area behind the subcrop of the Pekisko and consists of regional platform carbonates. To date, only a minor amount of proven gas has been discovered, and that as a result of drilling for deeper targets. Therefore, potential is assigned primarily to GRC 3. In GRC 1, wells with possible reserves contribute to the bulk of its undiscovered volume.

The undiscovered potential for this play area is estimated at 17.86×10^9 m^3 (634 Bcf), with estimates of the undiscovered pool size ranging up to two sections.

Ultimate Gas In Place

Pekisko Interval	Initial Gas In Place	Undiscovered 10^9 m^3				Ultimate Gas In Place
	10^9 m^3	GRC 1	GRC 2	GRC 3	Total	10^9 m^3
Play Area:						
1. Foothills (e.g. Limestone Field)	6.18	4.20	1.98	16.07	22.25	28.43
2. Subcrop – South-Central Alberta (e.g. Twining Field)	116.37	20.24	2.77	17.99	41.00	157.37
3. Subcrop – North-Central Alberta (e.g. Haro Field)	0.29	1.15	0.86	1.04	3.05	3.34
4. Platform Deposits Backstepping Subcrop – Western Alberta	1.78	0.58	0.00	17.28	17.86	19.64
Play Area Totals	124.62	26.17	5.61	52.38	84.16	206.78

BANFF/BAKKEN
INTERVAL

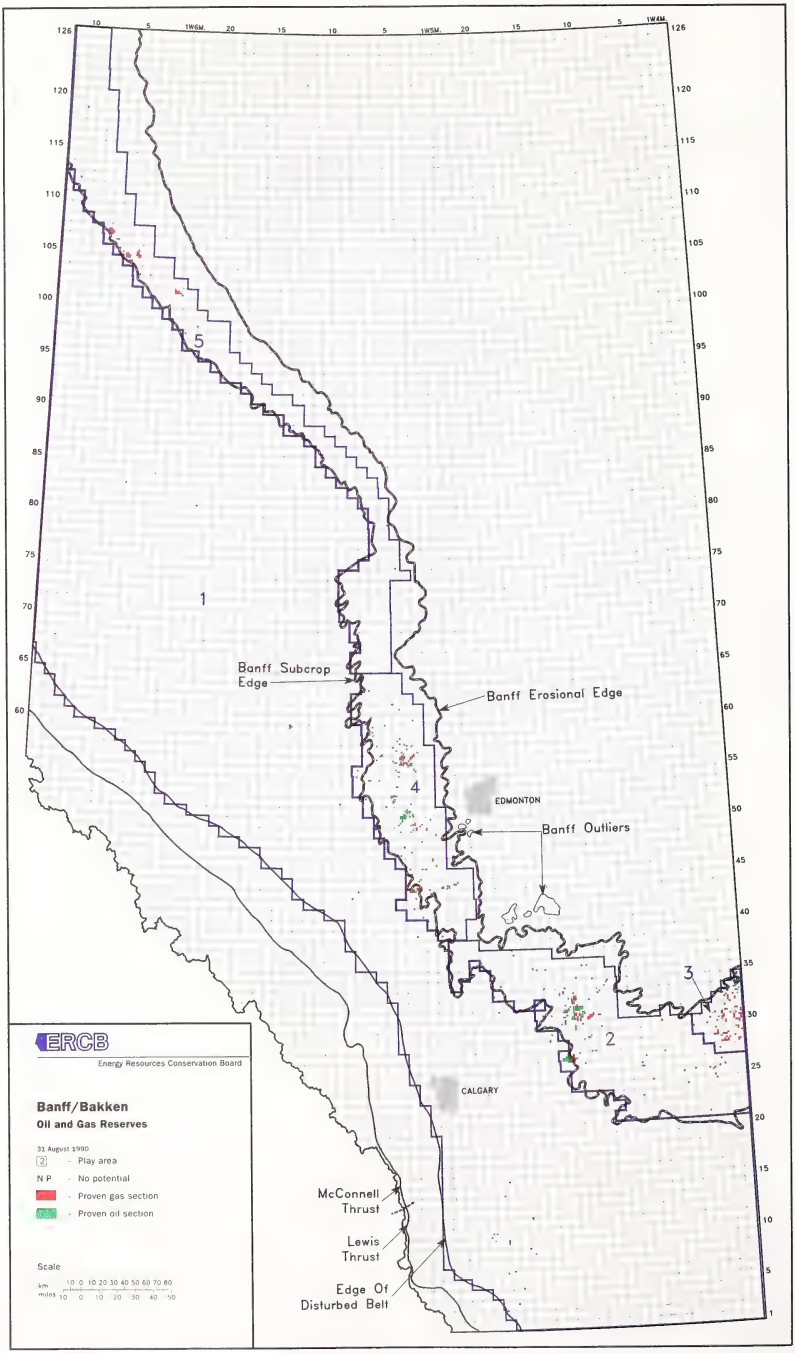

ERCB
Energy Resources Conservation Board
Banff/Bakken
Oil and Gas Reserves
31 August 1990
2 - Play area
N P - No potential
- Proven gas section
- Proven oil section
Scale
km 10 0 10 20 30 40 50 60 70 80
miles 10 0 10 20 30 40 50
Banff Subcrop Edge
Banff Erosional Edge
Banff Outliers
EDMONTON
CALGARY
McConnell Thrust
Lewis Thrust
Edge Of Disturbed Belt
1
2
3
4
5

FIGURE 28

D.28 Banff/Bakken Interval

Reservoir Parameters:

Maximum Pay Thickness	22 metres
Porosity Range	2 to 35%
Pool Size Range	< 1 to 21 sections
Gas Saturation Range	35 to 95%
Recovery Factor Range	50 to 90%

Number of Play Areas = 5

Play Area 1: Platform Deposits Backstepping Subcrop – Western Alberta

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	1	13	210	20	52
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	7	87	820	80	12 - 225
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-

Play Area 1 is characterized by regional Banff Formation platform carbonates downdip of the subcrop edge. It is bounded to the west by the eastern edge of the Disturbed Belt. Local reservoir development occurs because of drape over paleotopographic highs, normal faulting associated with basement tectonics and local fracturing causing porosity development. The normal faulting and fracturing make this a difficult exploration target. Potential was primarily assigned to GRC 3 due to the limited discovery of reserves to date. In GRC 1, wells with possible reserves contribute to the bulk of its undiscovered volume.

The undiscovered potential for this play area is estimated at 9.77×10^9 m^3 (347 Bcf), with estimates of the undiscovered pool size ranging up to two sections.

Play Area 2: Subcrop — South-Central Alberta
(e.g. Michichi Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	-	-	-	-	-
	Assoc.	5	5	1 010	19	1 - 60
	Sol'n	10	10	1 456	27	4 - 34
Two or less	Non-Assoc.	47	48	2 105	39	1 - 500
	Assoc.	9	9	253	5	2 - 72
	Sol'n	26	27	526	10	3 - 49

Play Area 2 is characterized by Banff Formation subcrop between the Banff and Pekisko erosional edges. The play area is further limited by transition into Bakken sandstones and siltstones in the east and the Clarke's Member to the north. Unconformity or stratigraphic traps in porous carbonate shelf rocks are the prevalent reservoir types. Additional gas is expected from new pools associated with karsted reservoirs.

The undiscovered potential for this play area is estimated at 7.36×10^9 m^3 (261 Bcf), with estimates of the undiscovered pool size ranging up to three sections.

Play Area 3: Bakken — Shelf Deposits — East-Central Alberta
(e.g. Esther Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	4	9	1 199	26	46 - 85
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	38	81	3 279	70	7 - 455
	Assoc.	5	11	174	4	2 - 75
	Sol'n	-	-	-	-	-

The Bakken Formation consists of sandstones, siltstones, shales and calcarenites and extends south and east into the Williston Basin. Play Area 3 is limited to the region in east-central Alberta where

reservoir quality, quartzose sandstones occur. The pools are predominantly stratigraphic with some structural influence from the North Battleford Arch.

Additional gas is expected primarily from the delineation of current trends. The undiscovered potential for this play area is estimated at 7.28×10^9 m^3 (258 Bcf), with estimates of the undiscovered pool size ranging up to two sections.

Play Area 4: Subcrop – Central Alberta
(e.g. Highvale Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	3	4	1 238	10	55 - 133
	Assoc.	1	1	365	3	73
	Sol'n	4	5	2 162	18	17 - 100
Two or less	Non-Assoc.	56	67	6 775	57	3 - 397
	Assoc.	12	14	802	7	2 - 250
	Sol'n	7	8	487	4	7 - 290

Play Area 4 is characterized by dolomitized shelf carbonates. It is limited to the subcrop between townships 39 and 64. Most of the pools are confined to the middle unit of the Banff Formation, informally called the Clarke's Member. The pools are contained as unconformity traps in paleotopographic highs, often in communication with overlying Jurassic zones (e.g. Nordegg "D" and Banff "H" Pool in the Highvale Field). Large portions of this play area are undrilled and could contain reserves associated with the extension of this play type.

Additional gas is expected from both pool expansions and discovery of new pools. The undiscovered potential for this play area is estimated at 18.04×10^9 m^3 (640 Bcf), with estimates of the undiscovered pool size ranging up to two sections.

Play Area 5: Subcrop – Northern Alberta
(e.g. Haro Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	5	25	681	72	13 - 26
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	15	75	267	28	3 - 37
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-

Play Area 5 consists of clastics and carbonates of the upper and middle Banff subcrop north of township 65. The middle Banff is characterized throughout the area by locally porous, shelf carbonates. The upper Banff, however, consists of sporadic occurrences of porous carbonates in the south changing to clastic zones in the northern portion of the play. Randomly scattered reservoirs are present in the clastic zone of the upper Banff capped by Mesozoic marine shales. Large areas of this play are given only limited potential due to the poor preservation of the clastic zone and the sporadic porosity development of the middle Banff. As with the Debolt in the northern subcrop, the Banff also contains high residual oil saturations resulting in lower IGIP than for other play areas. Future discoveries are expected to be affected by the same type of phenomenon.

Additional gas is expected primarily from the discovery of new pools. The undiscovered potential for this play area is estimated at 3.64×10^9 m^3 (129 Bcf) IGIP, with estimates of the undiscovered pool size ranging up to two sections.

Ultimate Gas In Place

Banff/Bakken Interval	Initial Gas In Place	Undiscovered 10^9 m^3				Ultimate Gas In Place
	10^9 m^3	GRC 1	GRC 2	GRC 3	Total	10^9 m^3
Play Area:						
1. Platform Deposits Backstepping Subcrop – Western Alberta	1.02	0.10	0.00	9.67	9.77	10.79
2. Subcrop – South-Central Alberta (e.g. Michichi Field)	5.35	2.69	0.29	4.38	7.36	12.71
3. Bakken – Shelf Deposits – East-Central Alberta (e.g. Esther Field)	4.65	4.40	1.42	1.46	7.28	11.93
4. Subcrop – Central Alberta (e.g. Highvale Field)	10.93	6.31	1.04	10.69	18.04	28.97
5. Subcrop – Northern Alberta (e.g. Haro Field)	0.95	0.78	0.04	2.82	3.64	4.59
Play Area Totals	22.90	14.28	2.79	29.02	46.09	68.99

WABAMUN/CROSSFIELD
INTERVAL

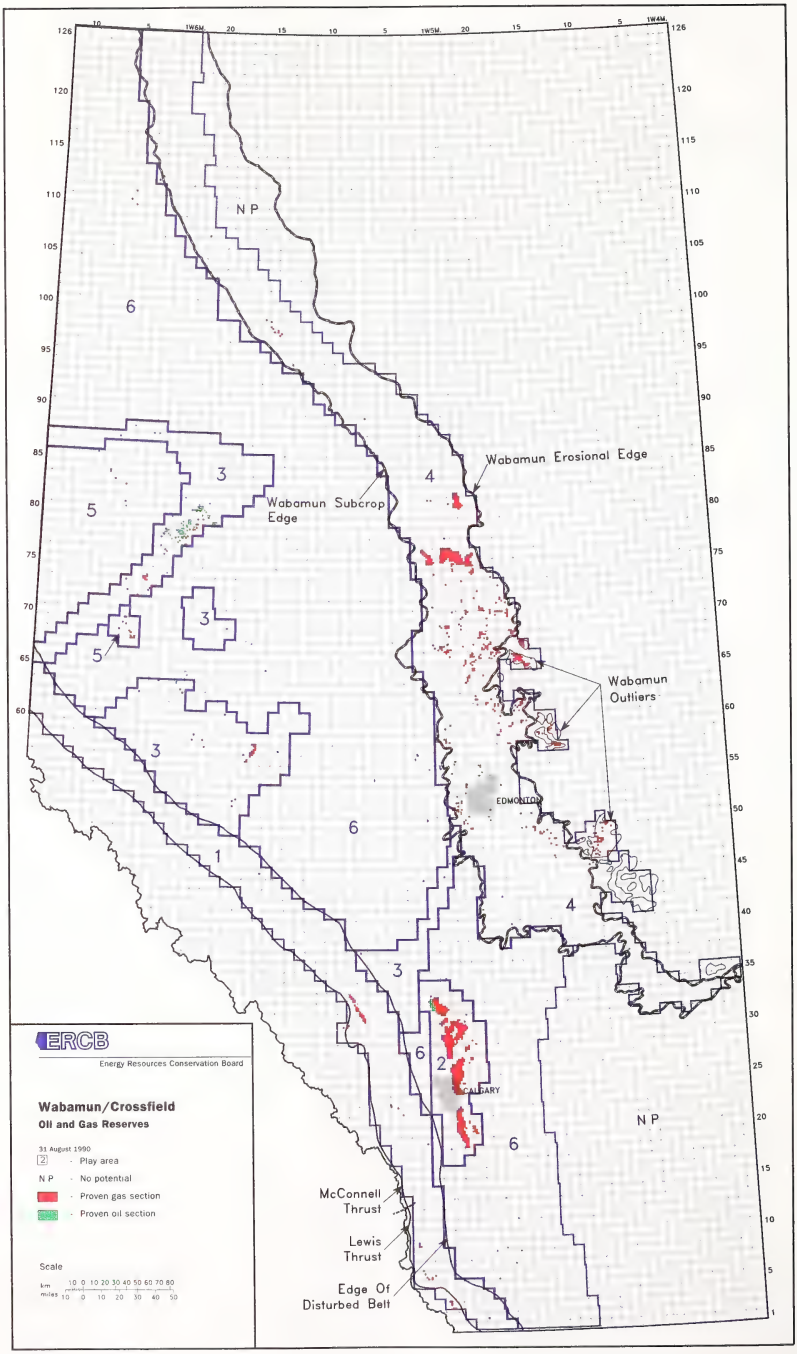

ERCB
Energy Resources Conservation Board
Wabamun/Crossfield
Oil and Gas Reserves
31 August 1990
2 - Play area
N P - No potential
- Proven gas section
- Proven oil section
Scale
km 10 0 10 20 30 40 50 60 70 80
miles 10 0 10 20 30 40 50
N P
6
3
5
4
1
2
Wabamun Subcrop Edge
Wabamun Erosional Edge
Wabamun Outliers
EDMONTON
CALGARY
McConnell Thrust
Lewis Thrust
Edge Of Disturbed Belt

FIGURE 29

D.29 Wabamun/Crossfield Interval

Reservoir Parameters:

Maximum Pay Thickness	127 metres
Porosity Range	1 to 30%
Pool Size Range	< 1 to 134 sections (4 TWPs)
Gas Saturation Range	23 to 90%
Recovery Factor Range	17 to 90%

Number of Play Areas = 6

Play Area 1: Foothills
(e.g. Pincher Creek Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	4	21	14 590	56	363 - 857
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	15	79	11 620	44	123 - 2 123
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-

Play Area 1 is characterized by platform dolomites and limestones of the Wabamun Formation. It is defined by the Disturbed Belt to the east and the McConnell and Lewis Thrusts to the west. Depositionally, the Wabamun represents a platform setting which contains minor primary porosity development. The degree of tectonic deformation which contributes to reservoir enhancement decreases with depth and therefore, risk increases with depth. These two factors have contributed to limited exploration for this zone.

The southern half of the play area contains the best potential for the Wabamun. The Wabamun is often a secondary target when drilling for Turner Valley structures, except in the Waterton area where it can be the primary target.

Potential was determined using the same method developed for the Turner Valley Play Area 1. Much of the area remains undrilled and the potential for undiscovered gas remains high. The present reserve distribution indicates that only a few large pools have been discovered. Therefore additional gas is expected from expansion of single sections as well as the discovery of new pools.

The undiscovered potential for this play area is estimated at 112.10 × 10^9 m^3 (3980 Bcf), with estimates of the undiscovered pool size ranging up to nine sections.

Play Area 2: Crossfield – Southwestern Alberta
(e.g. Crossfield Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	9	47	117 445	91	83 - 333
	Assoc.	1	5	8 709	7	158
	Sol'n	1	5	1 753	1	56
Two or less	Non-Assoc.	8	42	1 135	1	36 - 142
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-

Play Area 2 consists of dolomitized stromatoporoid mounds encased in supra to intertidal evaporites. It is defined by the depositional limits of the Crossfield Member. The play area is relatively mature and only minor pool expansions and small pools remain to be discovered.

The undiscovered potential for this play area is estimated at 18.76 × 10^9 m^3 (666 Bcf), with estimates of the undiscovered pool size ranging up to two sections.

Play Area 3: Platform Deposits Influenced by D-3 Reefs
(e.g. Obed and Tangent Fields)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	4	6	16 887	56	48 - 71
	Assoc.	-	-	-	-	-
	Sol'n	1	2	36	< 1	7
Two or less	Non-Assoc.	30	47	10 198	34	39 - 1 098
	Assoc.	11	17	2 208	7	1 - 544
	Sol'n	18	28	1 074	4	7 - 152

Play Area 3 is characterized by platform carbonates deposited over and influenced by D-3 reefs. It is limited to three geological settings: the Rimbey-Meadowbrook chain, the Obed-Windfall complex, and the Tangent-Normandville area. Structural deformation in the Rimbey-Meadowbrook and Obed-Windfall areas is the primary reservoir forming mechanism. In the Tangent-Normandville area the gas pools are also influenced by reservoir enhancing fluids percolating through Leduc reefs. Potential remains high for this zone especially in the Obed/Windfall complex due to the sparse drilling density.

Additional gas is expected primarily from new pools. The undiscovered potential for this play area is estimated at 76.09 $\times$ 10^9 m^3 (2701 Bcf), with estimates of the undiscovered pool size ranging up to four sections.

Play Area 4: Subcrop — Central and Northern Alberta
(e.g. Marten Hills Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	33	16	29 459	72	18 - 230
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	165	78	11 027	27	1 - 516
	Assoc.	5	2	243	< 1	12 - 81
	Sol'n	9	4	261	< 1	2 - 202

Play Area 4 is characterized by dolomitized platform carbonates. It is defined by the Wabamun and Winterburn erosional edges except where the Wabamun occurs above 300 metres. At shallower depths it is believed that all gas may have migrated to surface. Similar to the Mississippian subcrop plays, Play Area 4 reservoir parameters suggest, despite the sparse drilling, that much more gas could be discovered.

Additional gas is expected from both pool expansion and discovery of new pools. The undiscovered potential for this play area is estimated at 21.52 $\times$ 10^9 m^3 (764 Bcf), with estimates of the undiscovered pool size ranging up to five sections.

Play Area 5: Platform Deposits – Peace River Arch
(e.g. George Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	1	8	3 625	52	906
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	11	92	3 335	48	64 - 571
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-

Play Area 5 is characterized by Wabamun Formation limestones. It is limited to the area over the Peace River Arch where structural controls associated with extensional tectonics have controlled reservoir development. The Gold Creek Field is also included in this play area because of its similar geological setting. Historically, the Wabamun has not been a primary target in the area as reflected in the sparse well control. However, the high initial GIP values for the proven single-well pools along with limited development drilling of those pools indicates that the potential is significant in this zone.

Additional gas is expected primarily from the discovery of new pools. The undiscovered potential for this play area is estimated at 61.13×10^9 m^3 (2170 Bcf), with estimates of the undiscovered pool size ranging up to five sections.

Play Area 6: Platform Deposits Backstepping Subcrop – Western Alberta

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	-	-	-	-	-
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	8	100	429	100	15 - 153
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-

The platform carbonates behind the subcrop of the Wabamun not already defined by the other play areas constitute Play Area 6. To date, only a minor amount of proven gas has been discovered, and that as a result of drilling for deeper targets. Therefore, potential is assigned primarily to GRC 3. In GRC 1, wells with possible reserves contribute to the bulk of its undiscovered volume.

The undiscovered potential for this play area is estimated at 4.07 $\times$ 10^9 m^3 (144 Bcf), with estimates of the undiscovered pool size ranging up to two sections.

Ultimate Gas In Place

Wabamun/Crossfield Interval	Initial Gas In Place	Undiscovered 10^9 m^3				Ultimate Gas In Place
	10^9 m^3	GRC 1	GRC 2	GRC 3	Total	10^9 m^3
Play Area:						
1. Foothills (e.g. Pincher Creek Field)	26.21	27.3	16.73	68.04	112.10	138.31
2. Crossfield – Southwestern Alberta (e.g. Crossfield Field)	129.04	13.91	1.94	2.91	18.76	147.80
3. Platform Deposits Influenced by D-3 reefs (e.g. Obed and Tangent Fields)	30.40	12.37	4.04	59.68	76.99	108.49
4. Subcrop – Central and Northern Alberta (e.g. Marten Hills Field)	40.99	6.10	1.74	13.68	21.52	62.51
5. Platform Deposits – Peace River Arch (e.g. George Field)	6.96	12.11	6.92	42.10	61.13	68.09
6. Platform Deposits Backstepping Subcrop – Western Alberta	0.43	0.06	0.00	4.01	4.07	4.50
Play Area Totals	234.03	71.88	31.37	190.42	293.67	527.70

NISKU, BLUERIDGE, AND CAMROSE INTERVAL

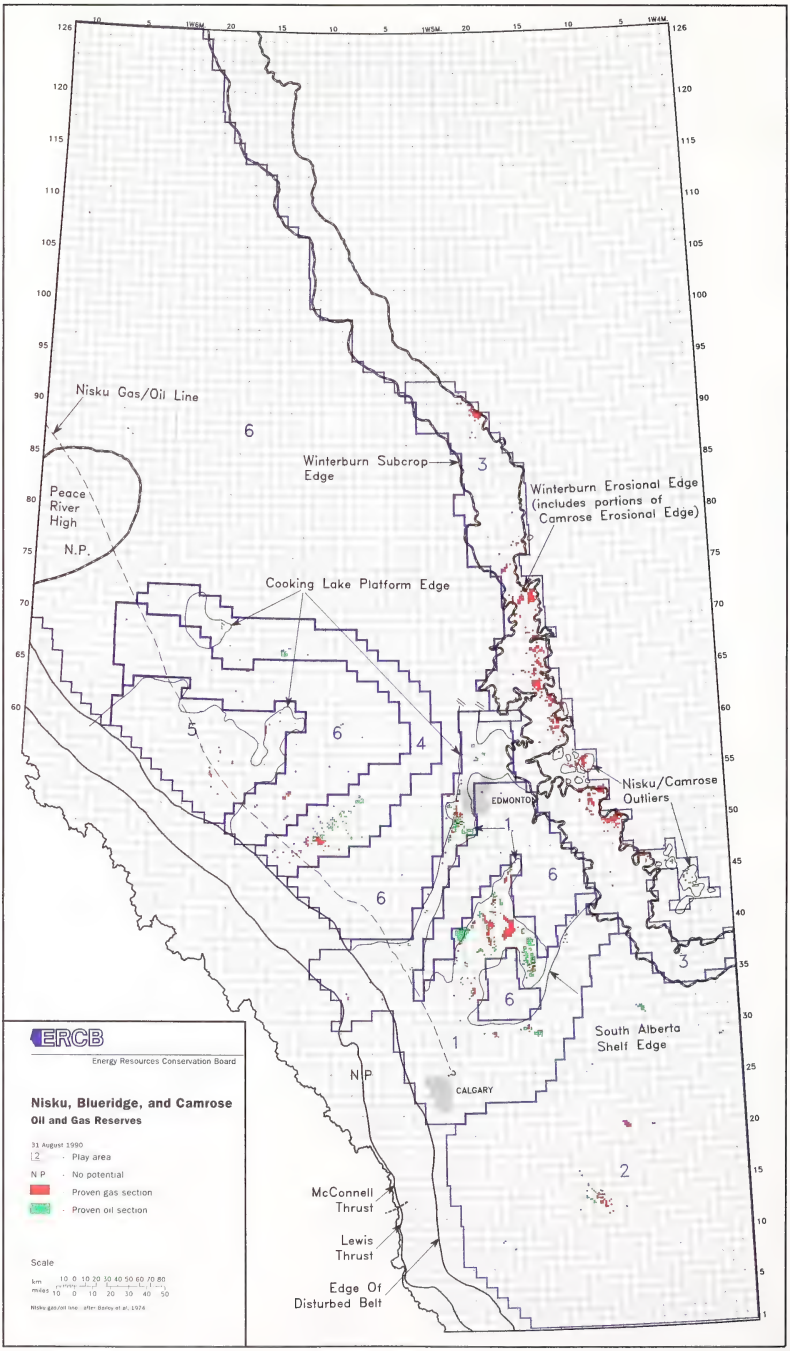

Nisku Gas/Oil Line
Peace River High
N.P.
Winterburn Subcrop Edge
Winterburn Erosional Edge (includes portions of Camrose Erosional Edge)
Cooking Lake Platform Edge
Nisku/Camrose Outliers
EDMONTON
South Alberta Shelf Edge
CALGARY
N.P.
McConnell Thrust
Lewis Thrust
Edge Of Disturbed Belt
ERCB
Energy Resources Conservation Board
Nisku, Blueridge, and Camrose
Oil and Gas Reserves
31 August 1990
Play area
N.P. No potential
Proven gas section
Proven oil section
Scale
km 10 0 10 20 30 40 50 60 70 80
miles 10 0 10 20 30 40 50
Nisku gas/oil line - after Bailey et al., 1974

FIGURE 30

D.30 Nisku, Blueridge and Camrose Interval

Reservoir Parameters:

Maximum Pay Thickness	60 metres
Porosity Range	2 to 31%
Pool Size Range	< 1 to 353 sections (10 TWPs)
Gas Saturation Range	55 to 90%
Recovery Factor Range	50 to 90%

Number of Play Areas = 6

Play Area 1: Platform Deposits in Foothills and Draping Over D-3 — Southern Alberta
(e.g. Limestone and Sylvan Lake Fields)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	-	-	-	-	-
	Assoc.	17	16	19 508	41	6 - 450
	Sol'n	25	23	19 141	40	3 - 100
Two or less	Non-Assoc.	22	20	5 079	11	5 - 951
	Assoc.	21	19	1 234	3	1 - 215
	Sol'n	24	22	2 327	5	2 - 266

In Play Area 1, the primary reservoir lithology is dolomitized tabular stromatoporoids and coral bioherms. The play area is limited to the Nisku Formation where it drapes over the Leduc Formation in the following areas: the Rimbey-Meadowbrook trend; the Bashaw, Clive and Wimborne complexes; and in fault-bounded structures in the foothills. The Nisku is mainly oil prone in this play and developed as a shoaling facies over the underlying Leduc which exerted strong controls on sedimentation patterns. Potential for the Nisku exists overlying the Leduc Formation or immediately adjacent to Leduc fairways, but is limited as the Rimbey-Meadowbrook trend deepens toward the foothills.

Additional gas is expected from both pool expansion and new pool discoveries. The undiscovered potential for this play area is estimated at 14.92×10^9 m^3 (530 Bcf), with estimates of the undiscovered pool size ranging up to three sections.

Play Area 2: Arcs Platform Deposits – Southern Alberta
(e.g. Enchant Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	1	4	1 014	27	78
	Assoc.	-	-	-	-	-
	Sol'n	1	4	40	1	3
Two or less	Non-Assoc.	16	57	2 117	57	13 - 388
	Assoc.	10	36	549	15	1 - 121
	Sol'n	-	-	-	-	-

The Arcs Member is generally a dolomitized unfossiliferous packstone and wackestone. Play Area 2 consists of the Arcs in Southern Alberta. The main play for the Arcs is the structural trap. Deep underlying Devonian salt solution and collapse is interpreted as the mechanism which has resulted in hydrocarbon traps in the Hays, Enchant, Princess, Youngstown and Pearce Fields. Drilling is sparse within this play area, and therefore, additional gas is expected in new pools.

The undiscovered potential for this play area is estimated at 26.65×10^9 m^3 (946 Bcf), with estimates of the undiscovered pool size ranging up to three sections.

Play Area 3: Nisku and Camrose Subcrop – East-Central Alberta
(e.g. Figure Lake Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	43	28	20 229	80	6 - 155
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	110	71	5 036	20	1 - 240
	Assoc.	2	1	115	<1	55 - 60
	Sol'n	-	-	-	-	-

Play Area 3 is characterized primarily by dolomitic framestones with abundant coral. It covers the erosional edge of the Nisku Formation and Camrose Member. The northern limit of the play area is

based on a depth cut-off of 300 metres above which, it is believed, all gas may have migrated to the surface. Gas is found in stratigraphic and structural traps between the Winterburn and Woodbend erosional edges. Potential exists in this play area for gas in the Camrose and Nisku. Since the erosional edge for the Camrose is poorly defined, the play could be somewhat larger than currently used.

Additional gas is expected from both pool expansion and new pool discoveries. The undiscovered potential for this play area is estimated at 22.87 $\times$ 10^9 m^3 (812 Bcf), with estimates of the undiscovered pool size ranging up to five sections.

Play Area 4: **Bank and Pinnacles – Central Alberta**
(e.g. West Pembina and Bigoray Fields)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	1	1	9 408	25	553
	Assoc.	-	-	-	-	-
	Sol'n	21	25	9 407	25	18 - 314
Two or less	Non-Assoc.	27	33	14 415	37	4 - 1 489
	Assoc.	8	10	99	<1	1 - 99
	Sol'n	26	31	4 695	12	1 - 791

Play Area 4 is exemplified by the Nisku Formation in the West Pembina, Bigoray, Meekwap, and Sturgeon Lake Fields. The carbonates were deposited at the shelf edge as bank deposits and as patch and pinnacle reefs. The Nisku Bank contains mainly non-associated gas which is often sour, while the Bigoray pinnacles contain primarily sweet solution gas. Much of the northern part of this play area is considered to be of limited potential because of the lack of proven reserves to date. Potential exists downdip into the Hanlan, Columbia and Peco Fields in pinnacle reefs and on the bank southwest of the Lodgepole area.

The undiscovered potential for this play area is estimated at 61.58 $\times$ 10^9 m^3 (2186 Bcf), with estimates of the undiscovered pool size ranging up to four sections.

Play Area 5: Drape over D-3 in Bigstone, Windfall and Fir – Central Alberta
(e.g. Obed Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	3	25	8 425	68	400 - 956
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	7	59	3 798	30	138 - 926
	Assoc.	1	8	257	2	257
	Sol'n	1	8	60	< 1	60

The Nisku Formation and Blueridge Member in Play Area 5 consist of shallow water carbonates. The play area is typified by the occurrences of non-associated gas where:

(1) the Nisku has developed over the Leduc Formation and includes fields such as Obed,
(2) the Nisku has developed in the absence of the Leduc (e.g. Cynthia Field), and
(3) the Blueridge has developed over the Nisku and Leduc.

The underlying Leduc in the Windfall, Obed and Fir Fields created shallow enough water conditions for the Nisku and, subsequently, the Blueridge to develop a shoaling facies. In the northwestern half of the play area, the Nisku is only developed on the fringe of the large underlying Leduc reef complexes. Porous Nisku has not been discovered to date within the fairways between the large complexes where "Berland type" Leduc pinnacles exist.

Since Blueridge potential is also included in this play area, more than one pay zone can be encountered.

Additional gas is expected primarily from new pools. The undiscovered potential for this play area is estimated at 70.14×10^9 m^3 (2490 Bcf), with estimates of the undiscovered pool size ranging up to six sections.

Play Area 6: **Blueridge and Winterburn – Northern and Central Alberta**
(e.g. Edson Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	2	12	1 799	34	75 - 149
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	14	82	3 506	66	27 - 988
	Assoc.	-	-	-	-	-
	Sol'n	1	6	15	<1	15

Play Area 6 is characterized primarily by platform and shelf carbonates. It includes the remainder of the area downdip from the Winterburn erosional edge and not already defined by Play Areas 1 through 5. The sporadic porosity developments over a wide area for the Nisku Formation (Winterburn Group) make this a difficult exploration target. Most of the potential appears in GRC 3.

The undiscovered potential for this play area is estimated at 41.42×10^9 m^3 (1470 Bcf), with estimates of the undiscovered pool size ranging up to six sections.

Ultimate Gas In Place

Nisku, Blueridge and Camrose Interval	Initial Gas In Place	Undiscovered 10^9 m^3				Ultimate Gas In Place
	10^9 m^3	GRC 1	GRC 2	GRC 3	Total	10^9 m^3
Play Area:						
1. Platform Deposits in Foothills and Draping over D-3 – Southern Alberta (e.g. Limestone and Sylvan Lake Fields)	47.29	4.00	2.79	8.13	14.92	62.21
2. Arcs Platform Deposits – Southern Alberta (e.g. Enchant Field)	3.72	7.11	1.04	18.50	26.65	30.37
3. Nisku and Camrose Subcrop – East-Central Alberta (e.g. Figure Lake Field)	25.38	7.54	2.56	12.77	22.87	48.25
4. Bank and Pinnacles – Central Alberta (e.g. West Pembina and Bigoray Fields)	37.62	17.91	9.95	33.72	61.58	99.20
5. Drape over D-3 in Bigstone, Windfall and Fir – Central Alberta (e.g. Obed Field)	12.54	15.65	14.38	40.11	70.14	82.68
6. Blueridge and Winterburn – Northern and Central Alberta (e.g. Edson Field)	5.32	5.59	1.11	34.72	41.42	46.74
Play Area Totals	131.87	57.80	31.83	147.95	237.58	369.45

LEDUC AND GROSMONT
INTERVAL

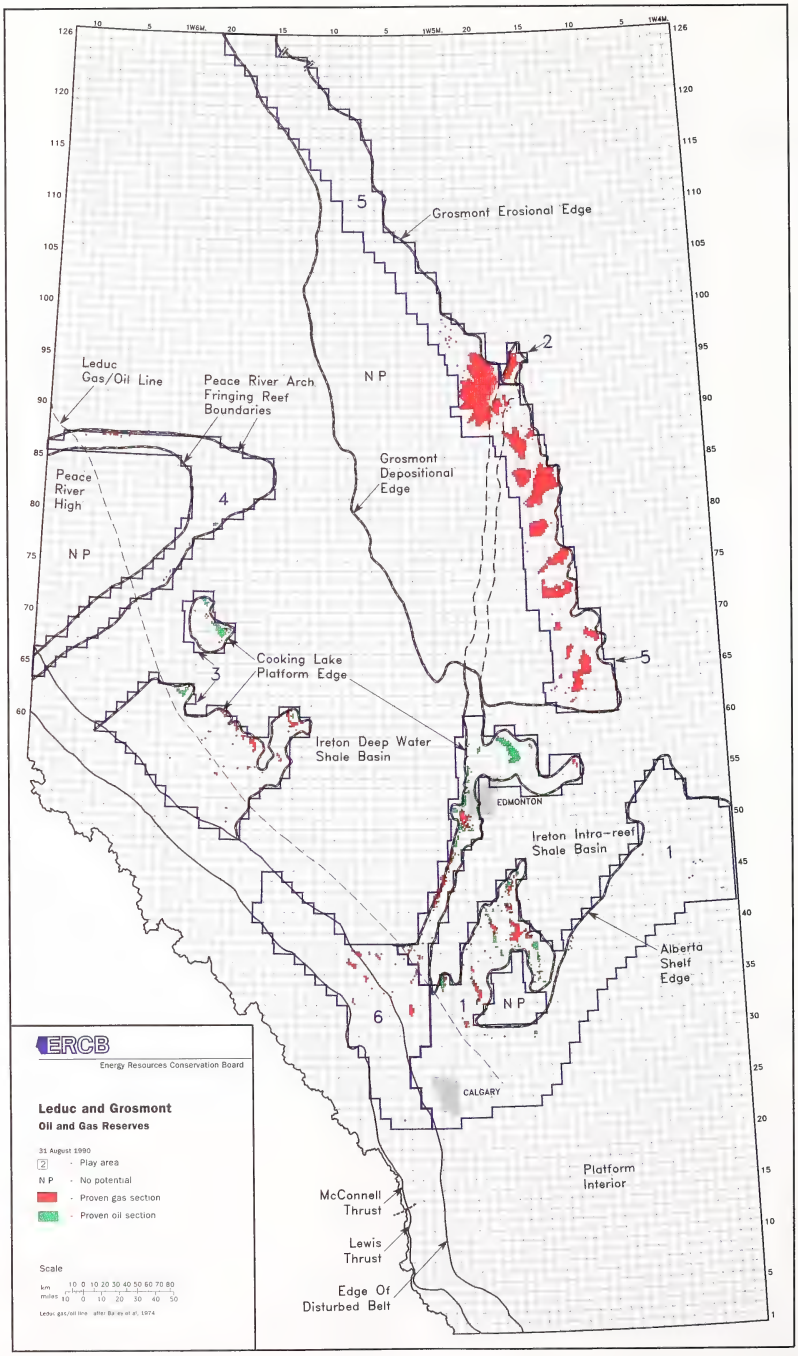

Grosmont Erosional Edge
Leduc Gas/Oil Line
Peace River Arch Fringing Reef Boundaries
Grosmont Depositional Edge
Peace River High
Cooking Lake Platform Edge
Ireton Deep Water Shale Basin
Ireton Intra-reef Shale Basin
Alberta Shelf Edge
EDMONTON
CALGARY
Platform Interior
McConnell Thrust
Lewis Thrust
Edge Of Disturbed Belt
N P
ERCB
Energy Resources Conservation Board
Leduc and Grosmont
Oil and Gas Reserves
31 August 1990
Play area
No potential
Proven gas section
Proven oil section
Scale

FIGURE 31

D.31 Leduc and Grosmont Interval

Reservoir Parameters:

Maximum Pay Thickness	197 metres
Porosity Range	3 to 35%
Pool Size Range	<1 to 365 sections (10 TWPs)
Gas Saturation Range	15 to 94%
Recovery Factor Range	10 to 90%

Number of Play Areas = 6

Play Area 1: Clive — Duhamel Reef Complexes — Central Alberta
(e.g. Bashaw Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	1	1	1 813	3	226
	Assoc.	11	14	38 534	68	13 - 450
	Sol'n	14	18	13 683	24	1 - 133
Two or less	Non-Assoc.	19	24	1 196	2	9 - 181
	Assoc.	18	23	526	1	1 - 118
	Sol'n	15	19	756	1	4 - 116

Play Area 1 is characterized by dolomitized reef complexes with occasional undolomitized carbonates. It is defined by the Cooking Lake platform edge underlying the Bashaw Complex and the limit of porosity development on the Southern Alberta Shelf margin. Although the Clive-Bashaw portion of the play area is extensively explored, most of the undiscovered gas is expected to occur in new pools in the form of fringing reefs associated with carbonate complexes. Potential was based on the number of those types of reefs yet to be discovered in the area between the Cooking Lake platform edge and the main Leduc complexes. Along the edge of the Southern Alberta Shelf in the eastern portion of the play, there is limited potential for future discoveries. Potential hydrocarbons could exist in porous rock adjacent to shale-filled tidal channels. Thus, most of the undiscovered gas is expected to be found in new pools.

The undiscovered potential for this play area is estimated at 3.81×10^9 m^3 (135 Bcf), with estimates of the undiscovered pool size ranging up to four sections.

Play Area 2: **Rimbey – Meadowbrook Reef Chain – Central Alberta**
(e.g. Westerose South Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	3	7	55 547	32	61 - 2 889
	Assoc.	6	12	61 139	35	39 - 1 223
	Sol'n	9	19	52 541	30	18 - 333
Two or less	Non-Assoc.	6	12	1 118	1	13 - 355
	Assoc.	6	12	1 311	1	2 - 769
	Sol'n	18	38	2 900	1	6 - 681

Play Area 2 is characterized by dolomitized reef complexes with occasional undolomitized carbonates. It is limited to the Rimbey-Meadowbrook trend. It includes the area northeast of the Grosmont erosional edge where the Liege Leduc Pool is located. This represents the northern-most limit of the trend. Subsurface migration of hydrocarbons into the overlying Grosmont has resulted in a lack of Leduc reserves over much of the trend. Therefore, that part of the trend between townships 61 and 92 has been excluded from the play area. A gas/oil line separates Play Area 2 from the gas-prone Play Area 6. Play Area 2 is extensively explored and, therefore, as with Play Area 1, potential was based on the number of reefs yet to be discovered in the area between the Cooking Lake platform and the main Leduc reef complexes.

The undiscovered potential for this play area is estimated at 5.44×10^9 m^3 (193 Bcf), with estimates of the undiscovered pool size ranging up to four sections.

Play Area 3: Windfall and Sturgeon Lake Reef Complexes – West Central Alberta
(e.g. Windfall Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	8	18	61 281	48	155 - 2 301
	Assoc.	3	7	21 621	17	111 - 925
	Sol'n	7	16	25 296	19	31 - 269
Two or less	Non-Assoc.	18	41	18 963	15	47 - 4 214
	Assoc.	4	9	115	<1	2 - 76
	Sol'n	4	9	627	<1	43 - 290

Play Area 3 is limited to the carbonate build-ups in the Windfall and Sturgeon Lake area. There are three main types of build-ups: large reef complexes surrounding lagoonal sediments; pinnacle reefs located in embayments between the large complexes; and stage one bioherms developed in deeper water on the seaward side of the complexes. To date, most of the gas has been discovered in large complexes such as Windfall and Fir. Lucrative targets such as the Berland pinnacle reefs have also been found while recent exploration has focused on stage one bioherms in the Windfall and Sturgeon Lake area. There is potential for more reefs to occur as stage one bioherms and as pinnacles in embayments. Also, depositional and erosional irregularities in the large reef complexes could result in sufficient closure to trap hydrocarbons.

Additional gas is based on an estimate of the number of reefs to be discovered. The undiscovered potential for this play area is estimated at 136.49×10^9 m^3 (4845 Bcf), with estimates of the undiscovered pool size ranging up to three sections.

Play Area 4: Peace River Arch Fringing Reefs – Northwestern Alberta
(e.g. Worsley Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	3	15	3 391	43	103 - 360
	Assoc.	-	-	-	-	-
	Sol'n	1	5	43	<1	14
Two or less	Non-Assoc.	14	70	4 448	56	3 - 760
	Assoc.	-	-	-	-	-
	Sol'n	2	10	63	<1	16 - 31

Play Area 4 is characterized by the occurrence of Leduc build-ups adjacent to the Peace River Arch. These build-ups are predominantly dolomite on the southeastern fringe and interbedded dolomite and sandstones along the northern flank. Porosity development is theorized to be post-depositional dolomitization that may be influenced by fluids flowing through Leduc carbonate beds as a result of tectonic movement of the Peace River Arch and deep basement faulting. Established reserves are predominantly gas on the northern reef fringe and predominantly oil on the southeastern fringe. Additional gas is expected from both expansion of existing pools and discovery of new pools. New pools could be located within the established Leduc cycle basinward of the current reserves and in a higher Leduc cycle backstepping the current reserves.

The undiscovered potential for this play area is estimated at 6.74×10^9 m^3 (239 Bcf), with estimates of the undiscovered pool size ranging up to six sections.

Play Area 5: Grosmont Subcrop — Northeastern Alberta
(e.g. Saleski Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	21	40	39 187	96	4 - 88
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	32	60	1 483	4	1 - 235
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-

Play Area 5 is characterized by fossiliferous limestones and dolomites of the Grosmont Formation. It is confined between the Grosmont erosional edge to the east and the downdip transition to regional aquifer to the west. Most of the established reserves are generally found in multi-section pools. Reserves development began at the southern end of the trend with current development of reserves towards the north in fields such as Liege and Saleski. Except for the Caribou Hills area, no potential was assigned north of township 100 because Grosmont occurs at depths of less than 300 metres. At these shallow depths, it is believed that all gas may have migrated to surface.

High residual oil saturations due to bitumen plugging has resulted in lower average IGIP values than for other play areas which will also affect future discoveries.

Additional gas is expected mainly in the central and northern portion of the play area as a result of both pool expansion and discovery of new pools. The undiscovered potential for this play area is estimated at 20.54×10^9 m^3 (729 Bcf), with estimates of the undiscovered pool size ranging up to 40 sections.

Play Area 6: Foothills and Gas-Prone Reef Complexes — Southwestern Alberta
(e.g. Limestone and Strachan Fields)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	5	18	117 816	87	360 - 5 820
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	23	83	17 145	13	62 - 3 578
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-

Play Area 6 is characterized by dolomitized Leduc reefs and fault-bounded reef build-ups. It includes the southwest extension of the Rimbey-Meadowbrook trend below the thermal hot line and is limited to the north and the south by depth cut-offs of 5000 metres. To date, non-associated gas reserves have been found in both autochthonous and allochthonous Leduc complexes. Potential was assigned to build-ups that could be found on trend with reserves or where geological data indicate fairways of both major reef build-ups and pinnacle reefs. In addition, outcrop data for the foothills was reviewed to determine whether faulting may have thrust reefs into new structures.

Additional gas is expected mainly in the discovery of new pools. The undiscovered potential for this play area is estimated at 53.06×10^9 m^3 (1884 Bcf), with estimates of the undiscovered pool size ranging up to 14 sections.

Ultimate Gas In Place

Leduc and Grosmont Interval	Initial Gas In Place	Undiscovered 10^9 m^3				Ultimate Gas In Place
	10^9 m^3	GRC 1	GRC 2	GRC 3	Total	10^9 m^3
Play Area:						
1. Clive – Duhamel Reef Complexes – Central Alberta (e.g. Bashaw Field)	56.50	0.78	0.78	2.25	3.81	60.31
2. Rimbey – Meadowbrook Reef Chain – Central Alberta (e.g. Westerose South Field)	174.56	1.73	0.83	2.88	5.44	180.00
3. Windfall and Sturgeon Lake Reef Complexes – West-Central Alberta (e.g. Windfall Field)	127.90	12.85	11.17	112.47	136.49	264.39
4. Peace River Arch Fringing Reefs – Northwestern Alberta (e.g. Worsley Field)	7.95	0.83	2.49	3.42	6.74	14.69
5. Grosmont Subcrop – Northeastern Alberta (e.g. Saleski Field)	40.67	7.52	4.10	8.92	20.54	61.21
6. Foothills and Gas-Prone Reef Complexes – Southwestern Alberta (e.g. Limestone and Strachan Fields)	134.95	9.54	20.74	22.78	53.06	188.02
Play Area Totals	542.54	33.25	40.11	152.72	226.08	768.62

SWAN HILLS AND SLAVE POINT INTERVAL

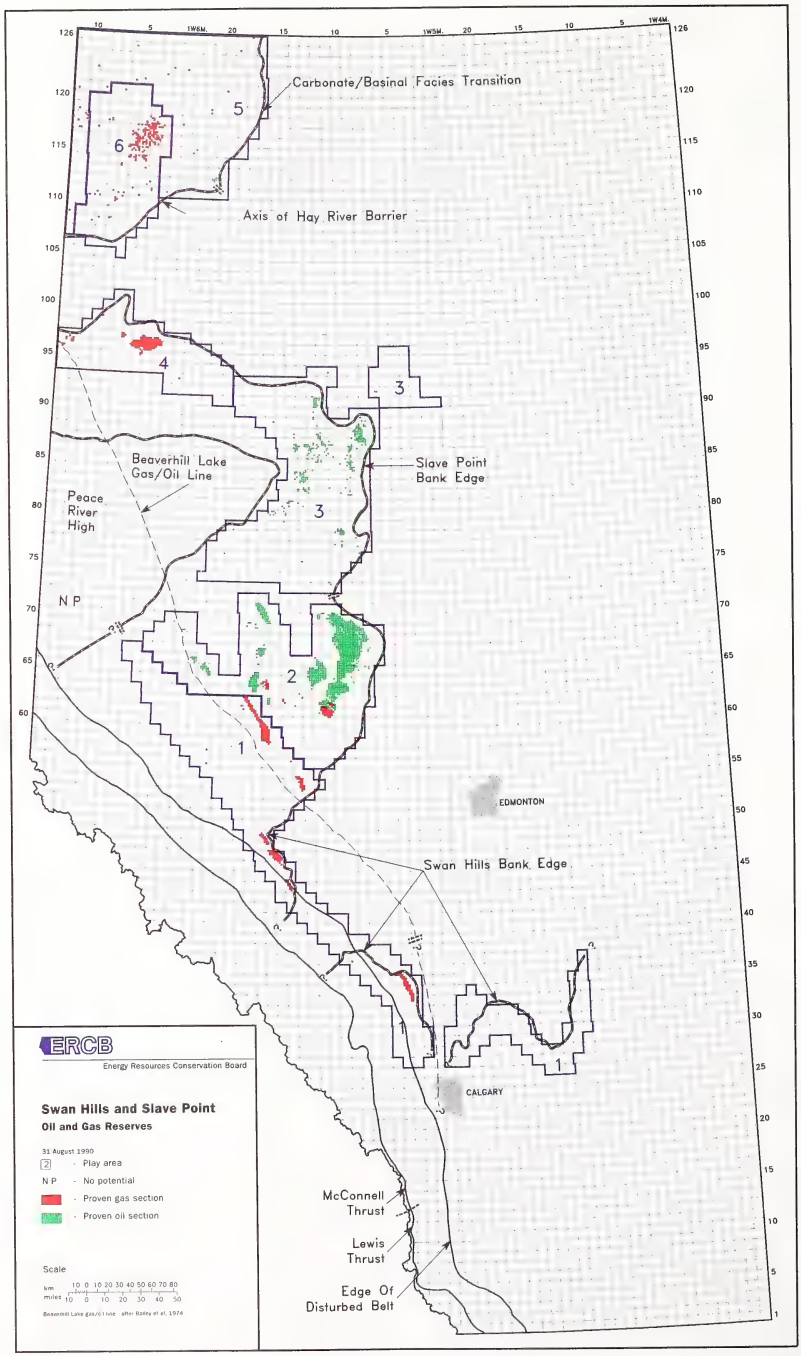

Carbonate/Basinal Facies Transition
Axis of Hay River Barrier
Beaverhill Lake Gas/Oil Line
Peace River High
Slave Point Bank Edge
Swan Hills Bank Edge
N P
EDMONTON
CALGARY
McConnell Thrust
Lewis Thrust
Edge Of Disturbed Belt
ERCB
Energy Resources Conservation Board
Swan Hills and Slave Point
Oil and Gas Reserves
31 August 1990
Play area
No potential
Proven gas section
Proven oil section
Scale
km
miles
Beaverhill Lake gas/oil line after Ramey et al, 1974

FIGURE 32

D.32 Swan Hills and Slave Point Interval

Reservoir Parameters:

Maximum Pay Thickness	31 metres
Porosity Range	5 to 20%
Pool Size Range	<1 to 157 sections (4 TWPs)
Gas Saturation Range	50 to 95%
Recovery Factor Range	45 to 90%

Number of Play Areas = 6

Play Area 1: Swan Hills – Reef Complexes – Central Alberta
(e.g. Caroline Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	7	58	248 394	99	396 - 1 607
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	5	42	1 906	1	111 - 1 299
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-

Play Area 1 is characterized by Swan Hills Formation dolomite lithologies and consists of two major depositional settings:

(1) carbonate stages backstepping onto the West Alberta Ridge (e.g. Caroline, Hanlan) and
(2) reef growth on platforms (e.g. Kaybob South and Wild River).

This play area is primarily gas prone within the Swan Hills Formation of central and southwestern Alberta. The play area extends from north of the Kaybob South Field to south of the Caroline Field and includes the area northeast of Calgary where the Swan Hills exists as a bank or shelf margin.

Large pools have been discovered in the most favourable positions along the leading edge of the Swan Hills. Potential also exists in stratigraphically higher Swan Hills cycles backstepped from these pools (e.g. 6-36-034-06W5). The present pool size distribution suggests that many smaller pools may yet be discovered. The gas type is non-associated and can be extremely sour.

The undiscovered potential for this play area is estimated at 340.19 × 10^9 m^3 (12 077 Bcf), with estimates of the undiscovered pool size ranging up to 11 sections.

Play Area 2: Swan Hills Oil Prone — Reef Complexes — Central Alberta
(e.g. Judy Creek Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	3	10	13 826	11	186 - 321
	Assoc.	6	20	819	1	1 - 91
	Sol'n	16	53	116 105	89	13 - 445
Two or less	Non-Assoc.	1	3	143	< 1	143
	Assoc.	3	10	116	< 1	1 - 58
	Sol'n	1	3	51	< 1	25

Play Area 2 is characterized by primary limestone. Large platform reefs form continuous complexes with small patch reefs existing in the shallow water between the complexes. The play area covers the oil-prone area of the Swan Hills from the Swan Hills and Carson Creek Fields to Snipe Lake and Ante Creek. Most of the gas reserves exist as solution gas with minor associated and non-associated gas. The undiscovered gas is expected to continue to be associated with new pool discoveries.

The undiscovered potential for this play area is estimated at 33.66 × 10^9 m^3 (1195 Bcf), with estimates of the undiscovered pool size ranging up to three sections.

Play Area 3: Slave Point Platform Deposits East of Peace River Arch
(e.g. Golden Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	-	-	-	-	-
	Assoc.	-	-	-	-	-
	Sol'n	2	20	223	33	8 - 14
Two or less	Non-Assoc.	1	10	117	17	117
	Assoc.	-	-	-	-	-
	Sol'n	7	70	338	50	4 - 163

Play Area 3 is characterized by Slave Point Formation shelf deposits which backstep onto the Peace River Arch in response to eustatic changes in sea level. Dolomitizing fluids flowing off the Peace River Arch result in reservoir development in a number of fields (e.g. Red Earth, Loon, Evi, Golden, and Slave Fields). The play area consists of oil-prone Slave Point south and east of the Peace River Arch.

To date, the solution gas in this play area is contained within pools that have gas/oil ratios low enough that it is marginally economic to conserve this gas. The initial GIP carried by the ERCB, for the few pools tabulated above, is estimated from the pool gas/oil ratios using a material balance calculation. The volume of undiscovered oil estimated in the ERCB oil supply study (ERCB Report 88-E) was used to calculate the undiscovered GIP with the result that the undiscovered potential for this play area is estimated at less than 0.01×10^9 m^3 (0.3 Bcf).

Play Area 4: Slave Point Platform Deposits North of Peace River Arch
(e.g. Cranberry Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	5	45	21 142	94	140 - 455
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	6	55	289	6	30 - 527
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-

The Slave Point Formation in Play Area 4 is a cyclical carbonate shelf facies which backsteps onto Slave Point margin to the southwest in response to eustatic sea level changes. It is limited to the gas-prone Slave Point north of the Peace River Arch. Large pools have been discovered in the Hamburg and Cranberry Fields. The present pool size distribution suggests that many smaller pools may yet be discovered, partially as a result of backstepping towards the margin in younger carbonate cycles.

The undiscovered potential for this play area is estimated at 48.71 $\times$ 10^9 m^3 (1729 Bcf), with estimates of the undiscovered pool size ranging up to six sections.

Play Area 5: Slave Point Platform Deposits — Northern Alberta

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	-	-	-	-	-
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	16	94	918	95	4 - 137
	Assoc.	1	6	52	5	52
	Sol'n	-	-	-	-	-

In Play Area 5 the Slave Point Formation is developed as shelf-interior patch reefs that geographically overlie the bank deposits of the Keg River Formation. The play area is limited by a transition from

carbonates to shale to the east and by the Rainbow, Shekilie and Zama basins to the west. Inconsistent porosity development in the patch reefs and sporadic reef development make the Slave Point reefs a difficult target. Presently, most of the gas is non-associated in one and two section pools and this scenario is expected to continue.

The undiscovered potential for this play area is estimated at 12.02×10^9 m^3 (427 Bcf), with estimates of the undiscovered pool size ranging up to two sections.

Play Area 6: Slave Point Drape – Northern Alberta
(e.g. Rainbow Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	1	1	434	9	108
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	192	99	4 316	91	1 - 341
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-

Play Area 6 is characterized by Slave Point Formation platform carbonates that drape over the underlying Keg River pinnacles. The play area is limited to the Rainbow, Shekilie and Zama basins. Non-associated gas is found in pool sizes that often mimic the areal extent of the underlying pinnacles. Slave Point pools in the Zama basin are often 24 hectares while the Rainbow pools are 32 to 64 hectares in size.

Potential was determined by reviewing the occurrences of Slave Point gas over Keg River structures and developing an occurrence ratio. Background work to ERCB Report 88-E was reviewed to determine the estimated number of pinnacles yet to be found. Using this value and the occurrence ratio the anticipated number of Slave Point pools was calculated.

The undiscovered potential for this play area is estimated at 6.26×10^9 m^3 (222 Bcf), with estimates of the undiscovered pool size ranging up to 1.5 sections.

Ultimate Gas In Place

Swan Hills and Slave Point Interval	Initial Gas In Place	Undiscovered 10^9 m^3				Ultimate Gas In Place
	10^9 m^3	GRC 1	GRC 2	GRC 3	Total	10^9 m^3
Play Area:						
1. Swan Hills – Reef Complexes – Central Alberta (e.g. Caroline Field)	250.30	43.52	47.15	249.52	340.19	590.49
2. Swan Hills – Oil Prone – Reef Complexes – Central Alberta (e.g. Judy Creek Field)	131.06	8.56	6.33	18.77	33.66	164.72
3. Slave Point Platform Deposits East of Peace River Arch (e.g. Golden Field)	0.68	0.00	0.00	0.00	0.00	0.68
4. Slave Point Platform Deposits North of Peace River Arch (e.g. Cranberry Field)	22.40	9.88	10.57	28.26	48.71	71.11
5. Slave Point – Platform Deposits – Northern Alberta	0.97	0.38	0.00	11.64	12.02	12.99
6. Slave Point Drape – Northern Alberta (e.g. Rainbow Field)	4.75	3.82	0.81	1.63	6.26	11.01
Play Area Totals	410.16	66.16	64.86	309.82	440.84	851.00

SULPHUR POINT
INTERVAL

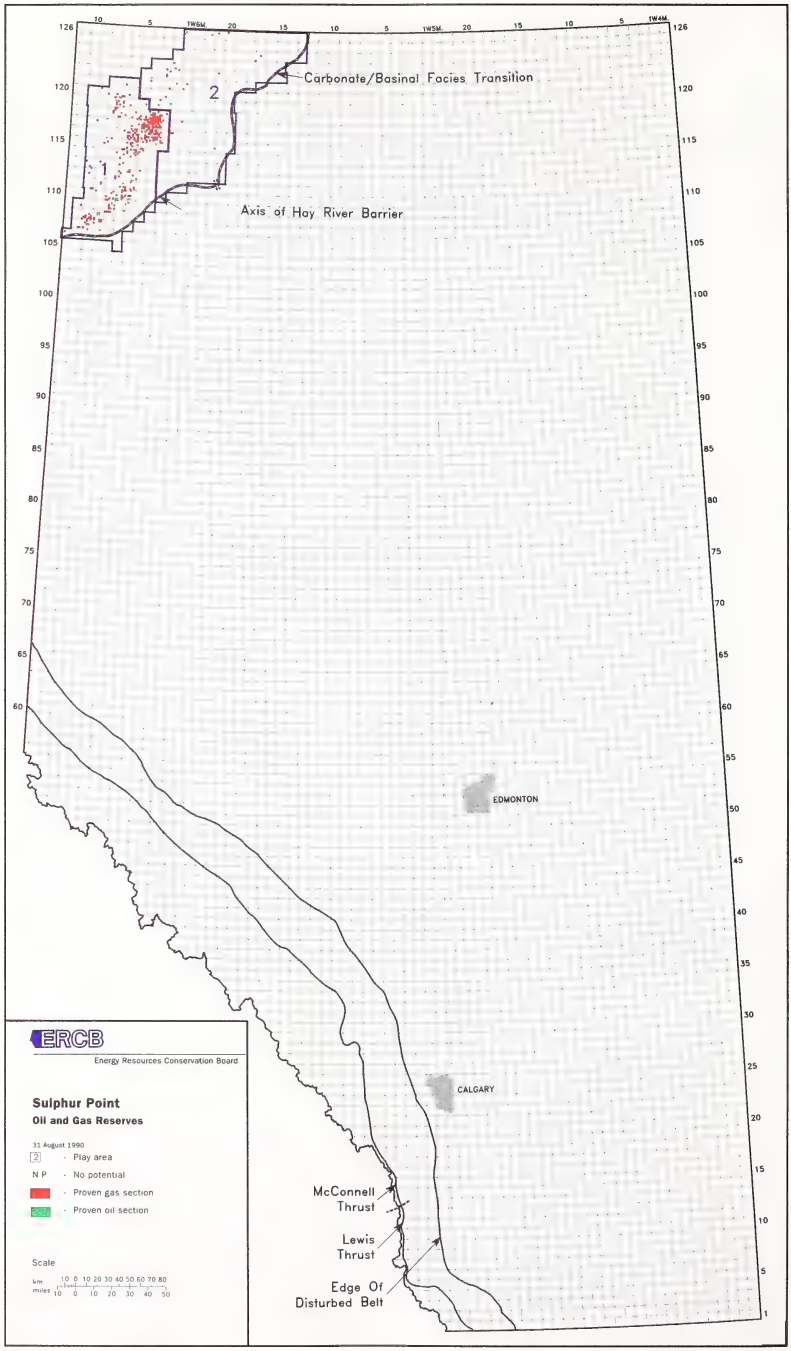

Carbonate/Basinal Facies Transition
Axis of Hay River Barrier
2
1
EDMONTON
CALGARY
McConnell Thrust
Lewis Thrust
Edge Of Disturbed Belt
ERCB
Energy Resources Conservation Board
Sulphur Point
Oil and Gas Reserves
31 August 1990
2 · Play area
N P · No potential
· Proven gas section
· Proven oil section
Scale
km 10 0 10 20 30 40 50 60 70 80
miles 10 0 10 20 30 40 50

FIGURE 33

D.33 Sulphur Point Interval

Reservoir Parameters:

Maximum Pay Thickness	29 metres
Porosity Range	3 to 15%
Pool Size Range	< 1 to 6 sections
Gas Saturation Range	50 to 90%
Recovery Factor Range	50 to 90%

Number of Play Areas = 2

Play Area 1: Drape Over Keg River – Northern Alberta
(e.g. Rainbow Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	4	1	946	7	19 - 149
	Assoc.	0	0	-	0	-
	Sol'n	4	1	385	3	6 - 38
Two or less	Non-Assoc.	288	90	11 764	87	1 - 419
	Assoc.	18	6	388	3	2 - 55
	Sol'n	5	2	67	< 1	4 - 20

In Play Area 1 the Sulphur Point Formation is a semi-restricted shelf carbonate that drapes over the underlying Keg River pinnacles. This play area is limited to the Rainbow, Shekilie and Zama basins. Gas is mainly non-associated and hydrocarbons in the Sulphur Point are not dependent on the existence of hydrocarbons in the underlying Keg River Formation.

Potential was determined by reviewing the occurrences of Sulphur Point gas over Keg River structures and developing an occurrence ratio. The background work to ERCB Report 88-E was reviewed to determine the number of pinnacles yet to be found. Using this number the anticipated number of Sulphur Point pools could be calculated.

The undiscovered potential for this play area is estimated at 15.14×10^9 m^3 (537 Bcf), with estimates of the undiscovered pool size ranging up to two sections.

Play Area 2: Platform Deposits – Northern Alberta

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	-	-	-	-	-
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	22	100	661	100	4 - 94
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-

In Play Area 2 the Sulphur Point Formation is a carbonate bank or shelf deposit that geographically overlies the bank deposits of the Keg River Formation. The play area is limited by a transition from carbonates to shale to the east and by the Rainbow, Shekilie and Zama basins to the west. Sporadic porosity occurrences make this zone a difficult exploration target. Most of the gas is non-associated and exists in small pools. This scenario is expected to continue.

The undiscovered potential for this play area is estimated at 3.66×10^9 m^3 (130 Bcf), with estimates of the undiscovered pool size ranging up to three sections.

Ultimate Gas In Place

Sulphur Point Interval	Initial Gas In Place	Undiscovered 10^9 m^3				Ultimate Gas In Place
	10^9 m^3	GRC 1	GRC 2	GRC 3	Total	10^9 m^3
Play Area:						
1. Drape over Keg River – Northern Alberta (e.g. Rainbow Field)	13.55	9.96	1.76	3.42	15.14	28.69
2. Platform Deposits – Northern Alberta	0.66	0.21	0.00	3.45	3.66	4.32
Play Area Totals	14.21	10.17	1.76	6.87	18.80	33.01

GILWOOD, GRANITE WASH, KEG RIVER, ZAMA, AND MUSKEG INTERVAL

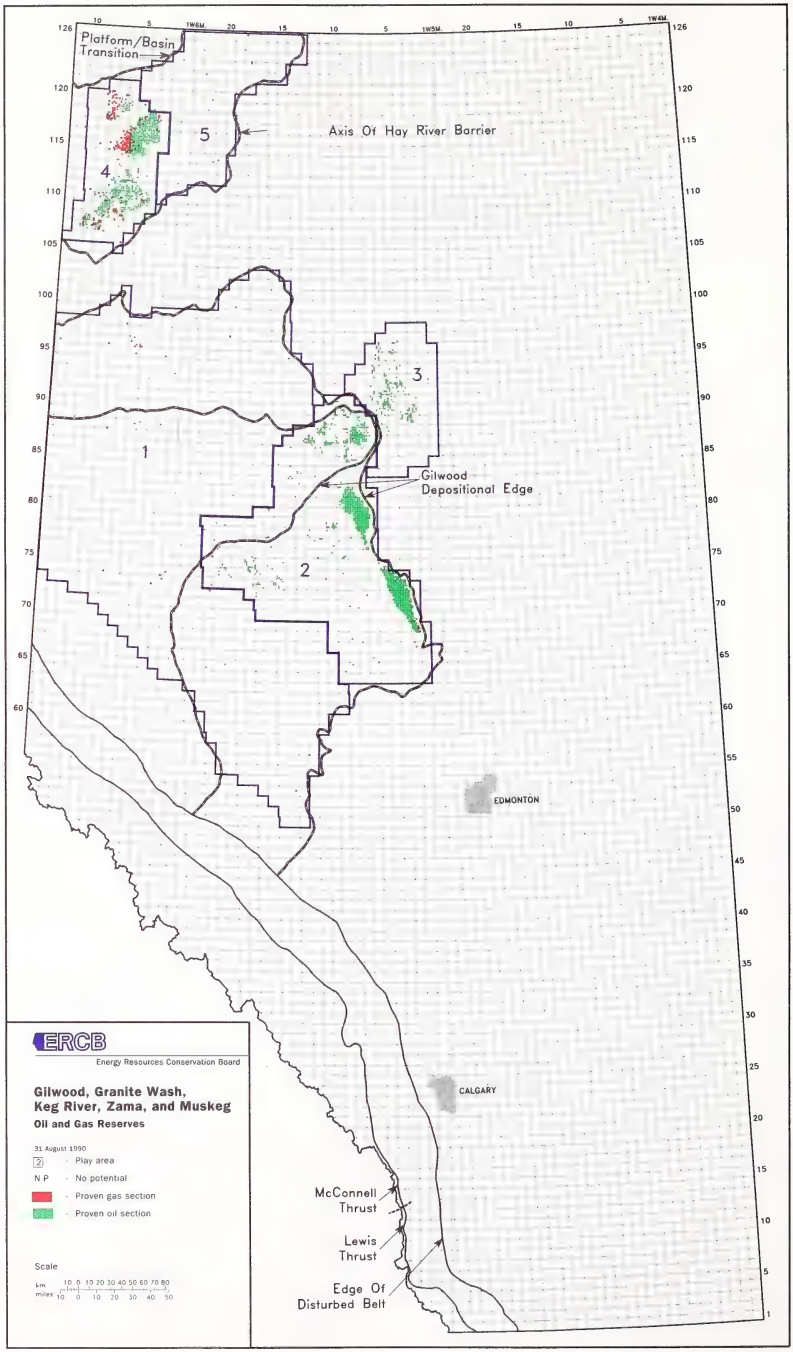

Platform/Basin Transition
Axis Of Hay River Barrier
Gilwood Depositional Edge
EDMONTON
CALGARY
McConnell Thrust
Lewis Thrust
Edge Of Disturbed Belt
1
2
3
4
5
ERCB
Energy Resources Conservation Board
Gilwood, Granite Wash, Keg River, Zama, and Muskeg
Oil and Gas Reserves
31 August 1990
Play area
N P · No potential
Proven gas section
Proven oil section
Scale
km
miles

FIGURE 34

D.34 Gilwood, Granite Wash, Keg River, Zama and Muskeg Interval

Reservoir Parameters:

Keg River, Zama and Muskeg:

Maximum Pay Thickness	122 metres
Porosity Range	3 to 17%
Pool Size Range	< 1 to 6 sections
Gas Saturation Range	15 to 94%
Recovery Factor Range	10 to 90%

Gilwood and Granite Wash:

Maximum Pay Thickness	25 metres
Porosity Range	8 to 22%
Pool Size Range	< 1 to 197 sections
Gas Saturation Range	55 to 90%
Recovery Factor Range	53 to 90%

Number of Play Areas = 5

Play Area 1: Gilwood and Granite Wash — Gas Prone — Peace River Arch
(e.g. Cranberry Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	2	11	618	21	34 - 136
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	16	84	2 225	76	20 - 540
	Assoc.	1	5	79	3	79
	Sol'n	-	-	-	-	-

The Gilwood Member and the Granite Wash consist of quartz and feldspathic sandstone, arkosic sandstone and conglomerates. Play Area 1 is limited to the gas-prone Granite Wash and Gilwood sediments around the Peace River Arch and West Alberta Ridge. The Granite Wash is the stratigraphically deepest gas-bearing zone in the province. Productive Granite Wash has been discovered in the centre of the play area on and around the arch. North and south of the arch, Gilwood would be the primary target with the Granite Wash a deeper, secondary target. Exploration strategies for the Granite Wash focus on the use of seismic data to locate sandstone accumulations

adjacent to basement structures. Gilwood pools are interpreted to be both stratigraphic and structural play types.

Additional gas is expected primarily from the discovery of new pools. The undiscovered potential for this play area is estimated at 30.38×10^9 m^3 (1078 Bcf), with estimates of the undiscovered pool size ranging up to five sections.

Play Area 2: Gilwood and Granite Wash — Oil Prone — Peace River Arch
(e.g. Mitsue and Red Earth Fields)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	-	-	-	-	-
	Assoc.	1	2	137	<1	137
	Sol'n	13	33	22 161	95	3 - 356
Two or less	Non-Assoc.	3	8	221	1	26 - 105
	Assoc.	7	18	557	2	29 - 172
	Sol'n	15	38	308	1	5 - 30

The extent of Play Area 2 is controlled by the deposition of the oil-prone Gilwood and Granite Wash sandstones. Recently, exploration for hydrocarbons has concentrated on the area to the west of the main Nipisi and Mitsue oil pools. Most of the undiscovered gas will be added through discoveries associated with oil pools related to block faulted structures.

Additional gas is expected primarily from the expansion of existing pools. The undiscovered potential for this play area is estimated at 0.50×10^9 m^3 (18 Bcf), with estimates of the undiscovered pool size ranging up to 1.5 sections.

Play Area 3: Keg River Patch Reefs — Oil Prone — North-Central Alberta
(e.g. Panny Field)

Play Area 3 consists of carbonate mudstone and patch reefs. It is limited to the depositional extent of the reefs. This oil-prone area has not been assigned any gas potential because of the low gas/oil ratios present in the current pool sample.

Play Area 4: Keg River, Zama and Muskeg in the Rainbow, Shekilie and Zama Basins – Northern Alberta

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	-	-	-	-	-
	Assoc.	12	2	1 096	2	1 - 152
	Sol'n	43	8	26 949	52	2 - 681
Two or less	Non-Assoc.	86	17	6 920	13	1 - 944
	Assoc.	95	19	5 204	10	1 - 586
	Sol'n	276	54	11 671	23	1 - 416

Play Area 4 is characterized by the presence of patch, pinnacle and drape traps of the Keg River, Zama and Muskeg Formations within the Rainbow, Zama and Shekilie basins. The current distribution of hydrocarbon shows that gas is more common in the Shekilie basin while oil is more common in the Rainbow basin. Also, pool size within the basins decreases towards the north. Typically, the Zama basin pools are 24 hectares in size whereas the Rainbow basin pools are 32 to 64 hectares in size.

The Keg River and Zama gas potential for this play area was determined by reviewing the ERCB Report 88-E and updating the estimated number of potential oil pools. To properly account for all gas types in the estimation of the undiscovered GIP, the present ratio of non-associated, associated and solution gas volumes were used assuming that future ratios would reflect historical ones.

Potential for the Muskeg drape traps was also calculated using the anticipated number of Keg River pinnacles in order to predict the number of undiscovered Muskeg pools. An occurrence ratio similar to that used for the Slave Point was applied to the Muskeg to determine potential.

Additional gas for these zones is expected both from expansion of existing pools and the discovery of new pools. The undiscovered potential for this play area is estimated at 22.88 $\times$ 10^9 m^3 (812 Bcf), with estimates of the undiscovered pool size ranging up to three sections.

Play Area 5: Keg River Platform Deposits – Northern Alberta
(e.g. Hutch Field)

Distribution of Proven Reserves In Place

Pool Size (sections)	Gas Type	No. of Pools	% of Total Pools	Total IGIP (10^6 m^3)	% of Total IGIP	Range in GIP/Sec (10^6 m^3)
Greater than two	Non-Assoc.	-	-	-	-	-
	Assoc.	-	-	-	-	-
	Sol'n	-	-	-	-	-
Two or less	Non-Assoc.	6	86	289	98	19 - 125
	Assoc.	-	-	-	-	-
	Sol'n	1	14	6	2	6

Play Area 5 is defined by the shelf area adjacent to the basins where the Keg River develops as patch reefs in a platform setting. The minimal discovery of reserves to date in this area leads to limited confidence in estimating undiscovered GIP. Therefore, potential is assigned only to GRC 3.

The undiscovered potential for this play area is estimated at 0.18×10^9 m^3 (6 Bcf), with estimates of the undiscovered pool size ranging up to two sections.

Ultimate Gas In Place

Gilwood, Granite Wash, Keg River, Zama and Muskeg Interval	Initial Gas In Place	Undiscovered 10^9 m^3				Ultimate Gas In Place
	10^9 m^3	GRC 1	GRC 2	GRC 3	Total	10^9 m^3
Play Area:						
1. Gilwood and Granite Wash – Gas Prone – Peace River Arch (e.g. Cranberry Field)	2.92	4.17	1.80	24.41	30.38	33.30
2. Gilwood and Granite Wash – Oil Prone – Peace River Arch (e.g. Mitsue and Red Earth Fields)	23.25	0.43	0.00	0.07	0.50	23.75
3. Keg River Patch Reefs – Oil Prone – North-Central Alberta (e.g. Panny Field)	0.00	0.00	0.00	0.00	0.00	0.00
4. Keg River, Zama, and Muskeg in the Rainbow, Shekilie and Zama Basins – Northern Alberta	51.84	8.82	4.71	9.35	22.88	74.72
5. Keg River Platform Deposits – Northern Alberta (e.g. Hutch Field)	0.03	0.00	0.00	0.18	0.18	0.21
Play Area Totals	78.04	13.42	6.51	34.01	53.94	131.98

List of References

(1) Bailey, N.J.L., Evans, C. R., and Milner, C.W.D., 1974. Applying Petroleum Geochemistry To Search For Oil: Examples from Western Canada Basin. **American Association of Petroleum Geologists Bulletin, v. 58,** pp. 2284-2294.

(2) Dahlstrom, C.D.A., 1970. Structural Geology In The Eastern Margin Of The Canadian Rocky Mountains. **Bulletin of Canadian Petroleum Geology, v. 18,** pp. 332-406.

(3) Energy Resources Conservation Board, 1988. **Alberta Oil Supply, 1988-2003.** ERCB Report 88-E, Calgary, Alberta.

(4) Gibson, D. W. and Barclay, J. E., 1989. Middle Absaroka Sequence: The Triassic Stable Craton. In: Western Canada Sedimentary Basin – A Case History, B. D. Ricketts (ed.). **Canadian Society of Petroleum Geologists, Special Publication No. 30**, Calgary, Alberta, pp. 219-232.

(5) Green, R., and Copeland, F. L., 1972. **Research Council of Alberta, Geological Map of Alberta.**

(6) Jackson, P. C., 1984. Paleogeography Of The Lower Cretaceous Mannville Group Of Western Canada. In: Elmworth, Case Study Of A Deep Basin Gas Field, J. A. Masters (ed.). **American Association of Petroleum Geologists Memoir 38,** pp. 49-77.

(7) Masters, J. A., 1979. Deep Basin Gas Trap, Western Canada. **American Association of Petroleum Geologists Bulletin, 63:** pp. 152-181.

(8) ---------, 1984. Lower Cretaceous Oil And Gas In Western Canada. In: Deep Basin Gas, J. A. Masters (ed.). **American Association of Petroleum Geologists Memoir 38,** pp. 1-34.

(9) Meijer-Drees, N. C., and Myhr, D. W., 1981. The Upper Cretaceous Milk River And Lea Park Formations in Southeastern Alberta. **Bulletin of Canadian Petroleum Geology, 29**, pp. 42-74.

(10) Podruski, J. A., Barclay, J. E., Hamblin, A. P., Lee, P. J., Osadetz, K. G., Proctor, R. M., and Taylor, G. C., 1987. Part I: Resource Endowment. In: Conventional Oil Resources of Western Canada (Light and Medium). **Geological Survey of Canada, Paper 87-26,** pp. 1-125.

(11) Thompson, M. J., 1989. Gas Fields, Formation-Fluid Flow And Hydrochemistry In Early Cretaceous Formations, Peace River Region, N.W. Alberta, Canada. **Unpublished M.Sc. Thesis, University of Alberta,** Edmonton, Alberta. pp. 160.

APPENDIX E GEOLOGICAL DATA AND RESULTS

TABLE E.1 Success Rates and Percentage of Play Area Drilled

Stratigraphic Interval	Play Area	Success Rate (%)			Percentage Drilled
		Provincial Data		Play Area Specific	
		GRC 1	GRC 2	GRC 3	
Paskapoo and Edmonton	1	70	50	1.8	60
	2	70	50	0.6	41
Belly River	1	80	-[1]	17.9	61
	2	70	-[1]	17.0	55
	3	70	-[1]	2.6	47
	4	70	-[1]	0.2	23
	5	75	-[1]	4.3	55
Chinook	1	80	50	1.1	17
Milk River	1	70	50	13.6	56
Medicine Hat	1	80	50	0.5	54
Cardium	1	70	50	11.4	12
	2	70	50	9.1	23
	3	80	50	17.0	62
	4	-[2]	-[2]	0.2	31
Doe Creek	1	70	50	4.3	42
Dunvegan	1	70	50	4.0	19
	2	70	50	3.8	42
Second White Specks	1	80	50	2.1	51
	2	-[2]	-[2]	0.7	34
	3	-[2]	-[2]	0.4	49
Base of Fish Scales	1	-[2]	-[2]	0.4	49
Viking	1	70	50	9.7	37
	2	70	50	13.6	56
	3	70	50	6.0	44
	4	70	50	6.0	16
	5	70	50	6.0	44
Basal Colorado	1	70	50	9.1	50
	2	70	50	2.2	47

TABLE E.1 (cont'd)

Stratigraphic Interval	Play Area	Success Rate (%)			Percentage Drilled
		Provincial Data		Play Area Specific	
		GRC 1	GRC 2	GRC 3	
Mannville above Glauconitic	1	70	-[1]	37.2	45
	2	70	-[1]	2.4	32
	3	70	-[1]	6.2	24
Glauconitic	1	70	-[1]	10.7	45
	2	70	50	10.7	29
	3	70	50	3.9	29
	4	85	60	6.4	19
Ostracod	1	70	50	3.2	29
	2	-[2]	-[2]	1.0	12
Ellerslie	1	70	-[1]	12.8	42
	2	70	50	8.7	32
	3	70	50	5.0	21
Cadomin	1	70	50	6.2	37
	2	70	50	7.3	24
	3	-[2]	-[2]	2.1	4
	4	70	50	9.4	29
	5	80	60	38.0	30
Nikanassin	1	70	50	18.1	48
	2	-[2]	-[2]	10.0	29
	3	70	50	6.6	21
Rock Creek	1	70	50	6.0	22
	2	70	50	3.6	32
	3	70	50	4.3	6
	4	70	50	4.9	27
Nordegg	1	70	50	4.5	22
	2	70	50	2.2	25
	3	70	50	12.2	46
	4	-[2]	-[2]	0.1	19
Baldonnel and Charlie Lake	1	70	50	7.4	23
Boundary	1	70	50	10.8	68
Halfway	1	70	50	16.0	26

TABLE E.1 (cont'd)

Stratigraphic Interval	Play Area	Success Rate (%)			Percentage Drilled
		Provincial Data		Play Area Specific	
		GRC 1	GRC 2	GRC 3	
Doig and Montney	1	85	50	34.2	51
	2	70	50	5.9	16
	3	70	50	5.4	31
Belloy	1	70	50	6.0	11
Kiskatinaw and Taylor Flat	1	70	50	6.0	15
Turner Valley	1	85	60	48.2	50
	2	85	50	9.4	22
	3	70	50	1.7	33
	4	80	50	10.4	21
	5	75	50	7.7	20
Shunda	1	-[2]	-[2]	0.1	8
	2	70	50	6.4	33
	3	70	50	13.6	20
Pekisko	1	85	50	8.8	26
	2	80	50	10.8	43
	3	70	50	3.9	19
	4	-[2]	-[2]	0.3	10
Banff/Bakken	1	-[2]	-[2]	0.1	10
	2	70	50	4.0	47
	3	70	50	11.6	51
	4	80	50	7.1	37
	5	70	50	10.9	18
Wabamun/Crossfield	1	80	50	15.8	23
	2	85	60	2.5	45
	3	70	50	7.0	12
	4	75	50	11.1	26
	5	70	50	5.5	7
	6	-[2]	-[2]	0.1	11
Nisku and Blueridge and Camrose	1	80	55	4.1	26
	2	75	50	5.0	4
	3	75	50	12.0	24
	4	80	50	5.5	15
	5	80	50	3.7	9
	6	70	50	2.4	7

TABLE E.1 (cont'd)

Stratigraphic Interval	Play Area	Success Rate (%)			Percentage Drilled
		Provincial Data		Play Area Specific	
		GRC 1	GRC 2	GRC 3	
Leduc and Grosmont	1	70	50	11.1	36
	2	70	50	25.3	81
	3	70	50	6.0	12
	4	70	50	14.7	41
	5	85	50	6.3	23
	6	70	50	17.1	36
Swan Hills and Slave Point	1	85	50	10.4	6
	2	80	50	3.5	23
	3	-[1]	-[1]	-[1]	21
	4	80	50	4.5	8
	5	70	50	2.9	4
	6	-[1]	-[1]	-[1]	32
Sulphur Point	1	-[1]	-[1]	-[1]	32
	2	70	50	2.3	4
Gilwood and Granite Wash	1	70	50	0.6	2
	2	-[2]	-[2]	0.4	4
	3	-[2]	-[2]	0.2	6
Keg River and Zama and Muskeg	1	-[1]	-[1]	-[1]	31
	2	-[2]	-[2]	2.3	5

1 Success rate based on alternative method (see Appendix D).

2 The play area was not analyzed using the Gas Resource Category method (See Appendix D for discussion).

TABLE E.2 Drilled versus Undrilled Sections by Geologic Period[1]

Period	Total Sections	Drilled		Undrilled		Proven		Initial Gas In Place	
		Sections	% of Total	Sections	% of Total	Sections	% of Total	10^9 m^3	Tcf
Upper Cretaceous	317 006	141 804	45	175 202	55	22 542	7	810.75	28.78
Lower Cretaceous	714 914	240 657	34	474 257	66	40 079	6	1 852.68	65.77
Jurassic	79 342	18 649	24	60 693	76	1 070	1	121.86	4.33
Triassic and Permian	68 741	12 667	18	56 074	82	1 176	2	117.02	4.15
Mississippian	254 858	42 333	17	212 525	83	3 490	1	1 096.36	38.92
Devonian	364 769	45 324	12	319 445	88	8 148	2	1 410.85	50.08
Provincial Totals	1 799 630	501 434	28	1 298 196	72	76 505	4	5 409.52	192.03

1 A count of drilled versus undrilled sections by geologic period. Sections are counted three-dimensionally and not geographically because more than one stratigraphic interval may be encountered in a section. Proven sections represent gas from all gas types. Proven percentages are based on percentage of the total sections. Tertiary has been included in the Upper Cretaceous.

TABLE E.3 Gas In Place Assessment Medium Case[1]

Period	Initial Gas In Place	Undiscovered					Ultimate Gas In Place	
		GRC 1	GRC 2	GRC 3	Total			
	10^9 m^3	10^9 m^3	10^9 m^3	10^9 m^3	10^9 m^3	Tcf	10^9 m^3	Tcf
Tertiary								
Paskapoo and Edmonton	1.73	2.33	0.37	1.40	4.10	0.1	5.83	0.2
Upper Cretaceous								
Belly River	96.53	32.88	3.47	28.11	64.46	2.3	160.99	5.7
Chinook	0.96	1.04	0.48	3.29	4.81	0.2	5.77	0.2
Milk River	166.31	42.48	14.17	1.33	57.98	2.1	224.29	8.0
Medicine Hat	194.55	44.67	13.75	0.48	58.90	2.1	253.45	9.0
Cardium	257.30	80.29	14.90	158.16	253.35	9.0	510.65	18.1
Doe Creek	8.07	3.98	1.35	1.92	7.25	0.3	15.32	0.5
Dunvegan	18.09	13.21	5.22	14.46	32.89	1.2	50.98	1.8
Second White Specks	66.38	32.10	14.75	7.94	54.79	1.9	121.17	4.3
Base of Fish Scales	0.83	0.13	0.00	1.15	1.28	0.0	2.11	0.1
Upper Cretaceous Totals	809.02	250.78	68.09	216.84	535.71	19.0	1 344.73	47.7

TABLE E.3 (cont'd)[1]

Period	Initial Gas In Place	Undiscovered					Ultimate Gas In Place	
		GRC 1	GRC 2	GRC 3	Total			
	10^9 m^3	10^9 m^3	10^9 m^3	10^9 m^3	10^9 m^3	Tcf	10^9 m^3	Tcf
Lower Cretaceous								
Viking	433.37	90.08	14.11	109.80	213.99	7.6	647.36	23.0
Basal Colorado	40.59	11.14	3.83	10.10	25.07	0.9	65.66	2.3
Mannville above Glauconitic	419.57	69.15	16.66	162.53	248.34	8.8	667.91	23.7
Glauconitic	437.86	99.75	30.23	222.70	352.68	12.5	790.54	28.1
Ostracod	29.33	9.58	7.68	26.37	43.63	1.5	72.96	2.6
Ellerslie	449.30	135.45	50.87	217.75	404.07	14.3	853.37	30.3
Cadomin	42.66	41.76	9.92	56.60	108.28	3.8	150.94	5.4
Mannville Totals	1 378.72	355.69	115.36	685.95	1 157.00	41.1	2 535.72	90.0
Lower Cretaceous Totals	1 852.68	456.91	133.30	805.85	1 396.06	49.6	3 248.74	115.3
Cretaceous Totals	2 661.70	707.69	201.39	1 022.69	1 931.77	68.6	4 593.47	163.1
Cumulative Totals	2 663.43	710.02	201.76	1 024.09	1 935.87	68.7	4 599.30	163.3
Jurassic								
Nikanassin	12.75	21.79	7.02	19.64	48.45	1.7	61.20	2.2
Rock Creek	43.05	31.44	7.87	48.36	87.67	3.1	130.72	4.6
Nordegg	66.06	22.17	6.19	39.99	68.35	2.4	134.41	4.8
Jurassic Totals	121.86	75.40	21.08	107.99	204.47	7.3	326.33	11.6
Cumulative Totals	2 785.29	785.42	222.84	1 132.08	2 140.34	75.98	4 925.63	174.9

TABLE E.3 (cont'd)[1]

Period	Initial Gas In Place	Undiscovered					Ultimate Gas In Place	
		GRC 1	GRC 2	GRC 3	Total			
	10^9 m^3	10^9 m^3	10^9 m^3	10^9 m^3	10^9 m^3	Tcf	10^9 m^3	Tcf
Triassic								
Baldonnel and Charlie Lake	8.42	12.72	2.97	15.93	31.62	1.1	40.04	1.4
Boundary	2.67	2.36	1.36	1.11	4.83	0.2	7.50	0.3
Halfway	38.62	18.63	7.65	35.52	61.80	2.2	100.42	3.6
Doig and Montney	57.53	21.47	8.73	52.04	82.24	2.9	139.77	5.0
Triassic Totals	107.24	55.18	20.71	104.60	180.49	6.4	287.73	10.2
Cumulative Totals	2 892.53	840.60	243.55	1 236.68	2 320.83	82.4	5 213.36	185.1
Permian								
Belloy	9.78	7.28	1.46	15.76	24.50	0.9	34.28	1.2
Cumulative Totals	2 902.31	847.88	245.01	1 252.44	2 345.33	83.3	5 247.64	186.3
Mississippian								
Kiskatinaw and Taylor Flat	22.22	8.64	1.92	18.16	28.72	1.0	50.94	1.8
Turner Valley	892.76	93.51	47.97	270.08	411.56	14.6	1 304.32	46.3
Shunda	33.86	11.71	2.34	14.74	28.79	1.0	62.65	2.2
Pekisko	124.62	26.17	5.61	52.38	84.16	3.0	208.78	7.4
Banff/Bakken	22.90	14.28	2.79	29.02	46.09	1.6	68.99	2.4
Mississippian Totals	1 096.36	154.31	60.63	384.38	599.32	21.3	1 695.68	60.2
Cumulative Totals	3 998.67	1 002.19	305.64	1 636.82	2 944.65	104.6	6 943.32	246.5

TABLE E.3 (cont'd)[1]

Period	Initial Gas In Place	Undiscovered					Ultimate Gas In Place	
		GRC 1	GRC 2	GRC 3	Total			
	10^9 m^3	10^9 m^3	10^9 m^3	10^9 m^3	10^9 m^3	Tcf	10^9 m^3	Tcf
Devonian								
Wabamun/Crossfield	234.03	71.88	31.37	190.42	293.67	10.4	527.70	18.7
Nisku, Blueridge and Camrose	131.87	57.80	31.83	147.95	237.58	8.4	369.45	13.1
Leduc and Grosmont	542.54	33.25	40.11	152.72	226.08	8.0	768.62	27.3
Swan Hills and Slave Point	410.16	66.16	64.86	309.82	440.84	15.6	851.00	30.2
Sulphur Point	14.21	10.17	1.76	6.87	18.80	0.7	33.01	1.2
Gilwood, Granite Wash, Keg River, Zama and Muskeg	78.04	13.42	6.51	34.01	53.94	1.9	131.98	4.7
Devonian Totals	1 410.85	252.68	176.44	841.79	1 270.91	45.1	2 681.76	95.2
Cumulative Totals	5 409.52	1 254.87	482.08	2 478.61	4 215.56	149.7	9 625.08	341.7
PROVINCIAL TOTALS	5 409.52	1 254.87	482.08	2 478.61	4 215.56	149.7	9 625.08	341.7

1 Discrepancies in subtotals and totals are due to rounding.

APPENDIX F DRILLING COST DATA

TABLE F.1 Drilling Costs – Area 1

Depth (m)	Drilled & Abandoned ($1991 Cdn.)	Drilled & Completed ($1991 Cdn.)
500	150 000	200 000
1 000	250 000	330 000
1 500	320 000	450 000
2 000	440 000	600 000
2 500	730 000	1 000 000
3 000	1 150 000	1 600 000
3 500	2 200 000	3 000 000
4 000	3 200 000	3 800 000
4 500	4 000 000	4 800 000
5 000	4 500 000	5 400 000
5 500	5 000 000	6 000 000
6 000	5 500 000	6 500 000

TABLE F.2 Drilling Costs – Area 2

Depth (m)	Drilled & Abandoned ($1991 Cdn.)	Drilled & Completed ($1991 Cdn.)
1 000	150 000	250 000
1 500	250 000	400 000
2 000	400 000	600 000
2 500	550 000	850 000
3 000	800 000	1 300 000
3 500	1 500 000	2 000 000
4 000	2 200 000	3 000 000
4 500	2 850 000	3 650 000
5 000	3 200 000	4 000 000
5 500	3 500 000	4 300 000

TABLE F.3 Drilling Costs – Area 3

Depth (m)	Drilled & Abandoned ($1991 Cdn.)	Drilled & Completed ($1991 Cdn.)
500	85 000	150 000
1 000	140 000	240 000
1 500	230 000	330 000
2 000	350 000	500 000
2 500	520 000	750 000
3 000	700 000	950 000
3 500	950 000	1 300 000

TABLE F.4 Drilling Costs – Area 4

Depth (m)	Drilled & Abandoned ($1991 Cdn.)	Drilled & Completed ($1991 Cdn.)
500	100 000	180 000
1 000	180 000	290 000
1 500	250 000	400 000
2 000	400 000	600 000

TABLE F.5 Drilling Costs – Area 5

Depth (m)	Drilled & Abandoned ($1991 Cdn.)	Drilled & Completed ($1991 Cdn.)
500	100 000	180 000
1 000	180 000	290 000
1 500	250 000	400 000
2 000	400 000	600 000

TABLE F.6 Drilling Costs – Area 6

Depth (m)	Drilled & Abandoned ($1991 Cdn.)	Drilled & Completed ($1991 Cdn.)
500	130 000	200 000
1 000	250 000	350 000
1 500	430 000	600 000

TABLE F.7 Drilling Costs – Area 7

Depth (m)	Drilled & Abandoned ($1991 Cdn.)	Drilled & Completed ($1991 Cdn.)
500	170 000	270 000
1 000	250 000	400 000
1 500	400 000	600 000
2 000	590 000	840 000
2 500	800 000	1 200 000
3 000	1 150 000	1 700 000

TABLE F.8 Drilling Costs – Area 8

Depth (m)	Drilled & Abandoned ($1991 Cdn.)	Drilled & Completed ($1991 Cdn.)
500	180 000	280 000
1 000	350 000	500 000
1 500	550 000	750 000
2 000	750 000	1 000 000
2 500	850 000	1 250 000
3 000	1 150 000	1 700 000

APPENDIX G CASH FLOW ANALYSIS RESULTS

TABLE G.1 Capital Costs Attributed to Gas — Area 1 — Commercial Full Cycle

Gas In Place to Achieve a 15% Rate of Return GIP — 10^6 m^3 Gas Price — 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
1 000	61.20	27.50	17.70	12.85	10.53	5.20
1 500	71.30	32.00	20.60	15.50	12.30	6.06
2 000	86.00	38.60	24.80	18.70	14.80	7.30
2 500	127.00	57.00	36.70	27.60	21.90	10.80
3 000	189.00	88.80	55.50	41.00	32.60	16.10
3 500	339.50	152.80	98.50	73.80	58.60	28.87
4 000	483.00	214.92	140.13	103.86	82.11	41.10
4 500	559.70	251.90	165.10	123.10	97.90	47.60
5 000	613.50	276.10	179.10	133.70	107.40	52.20
5 500	675.20	303.90	197.10	147.20	118.00	57.40
6 000	737.10	331.70	215.20	160.70	129.00	62.60

TABLE G.2 Capital Costs Attributed to Gas — Area 1 — Commercial Half Cycle

Gas In Place to Achieve a 15% Rate of Return GIP — 10^6 m^3 Gas Price — 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
1 000	33.00	14.69	9.61	7.16	5.69	2.82
1 500	35.65	15.97	10.30	7.70	6.13	3.04
2 000	39.99	18.06	11.69	8.69	6.92	3.44
2 500	50.80	22.86	14.92	11.05	8.64	4.38
3 000	68.04	30.24	19.84	14.74	11.71	5.76
3 500	106.90	48.20	31.60	23.10	18.65	9.16
4 000	144.90	65.00	42.80	31.30	25.28	12.27
4 500	162.30	73.00	47.90	35.06	28.32	14.00
5 000	176.70	79.60	52.20	38.40	30.83	14.96
5 500	193.00	86.40	57.00	41.72	33.42	16.54
6 000	210.00	94.40	62.00	45.39	36.30	17.78

TABLE G.3 Capital Costs Attributed to Gas – Area 1 – Economic Full Cycle

Gas In Place to Achieve a 15% Rate of Return GIP – 10^6 m^3 Gas Price – 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
1 000	38.40	16.68	10.70	7.80	6.18	3.00
1 500	44.02	19.10	12.21	9.02	7.14	3.48
2 000	53.32	23.13	14.79	10.84	8.58	4.16
2 500	77.60	33.66	21.59	15.75	12.45	6.03
3 000	113.40	50.09	31.75	23.06	18.33	8.88
3 500	200.30	86.60	55.60	41.20	32.40	15.80
4 000	280.14	120.75	77.28	56.51	44.44	21.72
4 500	328.50	142.20	91.20	66.60	53.20	25.70
5 000	355.80	155.20	98.80	73.60	57.70	28.20
5 500	391.60	170.80	108.70	79.70	63.50	31.00
6 000	431.20	188.00	119.40	87.70	69.30	33.80

TABLE G.4 Capital Costs Attributed to Gas – Area 1 – Economic Half Cycle

Gas In Place to Achieve a 15% Rate of Return GIP – 10^6 m^3 Gas Price – 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
1 000	21.60	9.40	6.00	4.40	3.48	1.70
1 500	23.29	10.08	6.43	4.76	3.73	1.82
2 000	25.89	11.27	7.14	5.25	4.13	2.01
2 500	32.26	13.97	8.92	6.54	5.17	2.53
3 000	41.96	18.33	11.72	8.51	6.80	3.31
3 500	64.50	28.20	18.00	13.20	10.50	5.10
4 000	85.49	37.19	23.67	17.39	13.67	6.67
4 500	97.90	42.50	26.90	19.90	15.70	7.60
5 000	104.90	45.40	29.10	21.50	16.90	8.30
5 500	113.40	49.50	31.60	23.10	18.20	9.00
6 000	123.80	53.80	34.30	25.10	19.80	9.70

TABLE G.5 Capital Costs Attributed to Gas — Area 1 — No Royalty Full Cycle

Gas In Place to Achieve a 15% Rate of Return GIP — 10^6 m^3 Gas Price — 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
1 000	42.40	18.00	11.60	8.40	6.60	3.24
1 500	49.70	21.09	13.35	9.70	7.68	3.76
2 000	59.34	25.19	16.25	11.78	9.29	4.56
2 500	86.36	36.70	23.62	17.15	13.60	6.60
3 000	126.63	54.24	34.97	25.52	20.22	9.83
3 500	224.10	95.10	61.10	44.10	35.30	17.00
4 000	318.80	135.24	85.50	62.79	49.30	23.70
4 500	369.40	156.80	100.70	72.80	58.20	28.00
5 000	404.90	171.80	109.20	79.80	63.20	30.70
5 500	445.60	189.00	119.50	87.10	68.90	33.40
6 000	486.40	206.30	131.20	95.60	75.90	36.80

TABLE G.6 Capital Costs Attributed to Gas — Area 1 — No Royalty Half Cycle

Gas In Place to Achieve a 15% Rate of Return GIP — 10^6 m^3 Gas Price — 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
1 000	24.00	10.20	6.48	4.74	3.75	1.83
1 500	25.92	11.01	6.99	5.11	4.04	1.97
2 000	28.81	12.21	7.74	5.68	4.47	2.18
2 500	35.90	15.24	9.68	7.07	5.60	2.73
3 000	46.87	19.85	12.66	9.26	7.31	3.55
3 500	73.00	31.00	19.70	14.20	11.40	5.40
4 000	96.60	41.10	26.10	18.80	15.00	7.30
4 500	109.70	46.70	29.70	21.80	17.00	8.40
5 000	118.40	50.30	31.90	23.32	18.40	9.00
5 500	128.30	54.70	34.70	25.30	19.90	9.70
6 000	138.60	59.30	37.60	27.60	21.70	10.60

TABLE G.7 Capital Costs Attributed to Gas – Area 2 – Commercial Full Cycle

Gas In Place to Achieve a 15% Rate of Return GIP – 10^6 m^3 Gas Price – 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
1 000	47.74	21.24	13.80	10.20	8.11	4.01
1 500	64.90	29.01	18.80	13.80	11.00	5.40
2 000	88.92	39.56	25.70	19.00	15.10	7.50
2 500	118.80	53.20	34.30	25.40	20.20	9.97
3 000	169.94	76.00	49.30	36.70	29.00	14.40
3 500	259.90	116.20	75.60	56.40	44.70	22.10
4 000	379.40	169.20	110.40	82.00	64.90	32.20
4 500	466.65	209.50	136.30	101.70	80.70	39.70
5 000	513.30	230.50	149.90	111.40	88.30	43.60
5 500	554.40	247.30	161.30	119.80	95.40	46.00

TABLE G.8 Capital Costs Attributed to Gas – Area 2 – Commercial Half Cycle

Gas In Place to Achieve a 15% Rate of Return GIP – 10^6 m^3 Gas Price – 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
1 000	28.50	12.70	8.25	6.11	4.87	2.41
1 500	35.94	16.00	10.00	7.70	6.10	3.00
2 000	46.23	20.60	13.40	9.90	7.90	3.90
2 500	59.04	26.30	17.10	12.60	10.10	5.00
3 000	81.40	36.30	23.70	17.50	13.90	6.90
3 500	118.80	53.20	34.40	25.30	20.03	10.10
4 000	169.60	75.90	49.30	36.30	28.90	14.30
4 500	206.70	92.40	59.96	44.70	35.40	17.50
5 000	225.30	101.10	65.70	48.20	38.50	19.00
5 500	241.70	108.10	70.40	52.10	41.60	20.50

TABLE G.9 Capital Costs Attributed to Gas — Area 2 — Economic Full Cycle

Gas In Place to Achieve a 15% Rate of Return GIP — 10^6 m^3 Gas Price — 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
1 000	29.48	12.90	8.20	6.00	4.80	2.30
1 500	39.70	17.30	11.10	8.10	6.40	3.10
2 000	54.10	23.60	15.00	11.00	8.74	4.30
2 500	71.30	31.00	19.80	14.70	11.50	5.60
3 000	101.30	44.20	28.20	20.70	16.40	8.00
3 500	154.38	67.30	43.01	31.60	24.95	12.20
4 000	224.20	97.50	62.40	45.90	36.20	17.70
4 500	276.30	120.40	76.80	56.50	44.70	21.80
5 000	302.80	131.70	84.20	61.90	49.02	23.90
5 500	325.40	141.90	90.60	66.50	52.70	25.70

TABLE G.10 Capital Costs Attributed to Gas — Area 2 — Economic Half Cycle

Gas In Place to Achieve a 15% Rate of Return GIP — 10^6 m^3 Gas Price — 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
1 000	18.30	8.00	5.10	3.80	2.97	1.45
1 500	22.80	9.90	6.30	4.70	3.70	1.80
2 000	28.90	12.60	8.05	5.90	4.70	2.29
2 500	36.50	15.90	10.20	7.50	5.90	2.90
3 000	49.60	21.60	13.80	10.10	8.02	3.90
3 500	71.60	31.20	19.90	14.70	11.60	5.60
4 000	101.70	44.20	28.30	20.80	16.40	8.02
4 500	123.20	53.70	34.30	25.20	19.90	9.70
5 000	134.20	58.50	37.40	27.50	21.70	10.60
5 500	143.60	62.60	40.03	29.40	23.20	11.40

TABLE G.11 Capital Costs Attributed to Gas – Area 2 – No Royalty Full Cycle

Gas In Place to Achieve a 15% Rate of Return GIP – 10^6 m^3 Gas Price – 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
1 000	32.30	13.90	8.90	6.50	5.10	2.50
1 500	43.70	18.90	12.00	9.00	6.90	3.40
2 000	59.20	25.50	16.30	11.90	9.06	4.40
2 500	78.30	33.70	21.50	15.80	12.50	6.10
3 000	111.50	48.00	30.60	22.40	17.70	8.70
3 500	170.20	73.30	46.80	34.30	27.00	13.20
4 000	246.99	106.20	67.90	49.70	39.30	19.20
4 500	304.70	131.10	83.50	61.40	48.50	23.70
5 000	333.60	143.70	91.90	67.20	53.20	25.90
5 500	360.40	155.20	99.20	72.60	57.50	27.90

TABLEG.12 Capital Costs Attributed to Gas – Area 2 – No Royalty Half Cycle

Gas In Place to Achieve a 15% Rate of Return GIP – 10^6 m^3 Gas Price – 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
1 000	19.98	8.60	5.50	4.02	3.20	1.55
1 500	24.90	10.70	6.80	5.00	3.90	1.90
2 000	31.60	13.60	8.60	6.30	5.00	2.40
2 500	39.80	17.10	10.90	8.00	6.30	3.10
3 000	54.40	23.30	14.80	10.90	8.60	4.20
3 500	78.20	33.80	21.40	15.90	12.50	6.10
4 000	111.20	47.80	30.40	22.40	17.60	8.60
4 500	135.30	58.30	36.90	27.10	21.50	10.50
5 000	147.30	63.70	40.60	29.80	23.50	11.50
5 500	158.00	68.20	43.50	31.90	25.20	12.20

TABLE G.13 Capital Costs Attributed to Gas — Area 3 — Commercial Full Cycle

Gas In Place to Achieve a 15% Rate of Return GIP — 10^6 m^3 Gas Price — 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	36.80	14.70	9.21	6.80	5.30	2.60
1 000	52.98	21.10	13.30	9.80	7.70	3.70
1 500	74.80	29.90	18.90	13.80	10.90	5.30
2 000	104.70	41.90	26.40	19.40	15.20	7.40
2 500	147.70	59.10	37.20	27.30	21.40	10.50

TABLE G.14 Capital Costs Attributed to Gas — Area 3 — Commercial Half Cycle

Gas In Place to Achieve a 15% Rate of Return GIP — 10^6 m^3 Gas Price — 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	24.70	9.80	6.20	4.50	3.60	1.70
1 000	35.50	14.10	8.90	6.50	5.10	2.50
1 500	51.60	20.40	12.90	9.50	7.50	3.60
2 000	70.10	27.90	17.60	12.90	10.20	4.90
2 500	97.50	38.70	24.40	17.90	14.10	6.90

TABLE G.15 Capital Costs Attributed to Gas — Area 3 — Economic Full Cycle

Gas In Place to Achieve a 15% Rate of Return GIP — 10^6 m^3 Gas Price — 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	23.05	8.98	5.59	4.02	3.15	1.52
1 000	32.50	12.64	7.84	5.67	4.49	2.14
1 500	46.15	17.95	11.15	8.08	6.34	3.05
2 000	63.68	24.72	15.29	11.10	8.74	4.19
2 500	88.75	34.70	21.56	15.65	12.25	5.91

TABLE G.16 Capital Costs Attributed to Gas – Area 3 – Economic Half Cycle

Gas In Place to Achieve a 15% Rate of Return GIP – 10^6 m^3 Gas Price – 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	15.98	6.20	3.85	2.80	2.19	1.06
1 000	22.24	8.62	5.40	3.90	3.04	1.47
1 500	32.17	12.57	7.82	5.64	4.41	2.13
2 000	43.46	16.86	10.53	7.62	5.97	2.86
2 500	59.66	23.18	14.47	10.48	8.20	3.94

TABLE G.17 Capital Costs Attributed to Gas – Area 3 – No Royalty Full Cycle

Gas In Place to Achieve a 15% Rate of Return GIP – 10^6 m^3 Gas Price – 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	25.13	9.88	6.09	4.42	3.45	1.68
1 000	35.59	13.83	8.62	6.19	4.90	2.36
1 500	50.12	19.45	12.04	8.75	6.85	3.29
2 000	69.02	26.81	16.55	12.04	9.43	4.56
2 500	95.84	37.66	23.18	16.83	13.22	6.35

TABLE G.18 Capital Costs Attributed to Gas – Area 3 – No Royalty Half Cycle

Gas In Place to Achieve a 15% Rate of Return GIP – 10^6 m^3 Gas Price – 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	17.42	6.83	4.22	3.07	2.40	1.16
1 000	24.14	9.42	5.83	4.23	3.33	1.60
1 500	34.79	13.47	8.38	6.06	4.77	2.29
2 000	46.60	18.07	11.26	8.17	6.39	3.07
2 500	64.38	24.88	15.51	11.22	8.86	4.24

TABLE G.19 Capital Costs Attributed to Gas — Area 4 — Commercial Full Cycle

Gas In Place to Achieve a 15% Rate of Return GIP — 10^6 m^3 Gas Price — 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	49.80	19.17	12.05	8.76	6.92	3.36
1 000	71.66	27.73	17.41	12.68	9.96	4.87
1 500	92.08	35.60	22.37	16.30	12.89	6.26
2 000	131.67	50.96	32.00	23.31	18.43	8.95

TABLE G.20 Capital Costs Attributed to Gas — Area 4 — Commercial Half Cycle

Gas In Place to Achieve a 15% Rate of Return GIP — 10^6 m^3 Gas Price — 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	31.62	12.20	7.62	5.58	4.38	2.12
1 000	43.70	16.84	10.61	7.74	6.09	2.94
1 500	54.97	21.18	13.35	9.67	7.64	3.71
2 000	76.37	29.63	18.43	13.56	10.67	5.19

TABLE G.21 Capital Costs Attributed to Gas — Area 4 — Economic Full Cycle

Gas In Place to Achieve a 15% Rate of Return GIP — 10^6 m^3 Gas Price — 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	30.88	11.75	7.27	5.23	4.11	1.97
1 000	43.71	16.63	10.25	7.45	5.84	2.79
1 500	56.17	21.37	13.08	9.48	7.46	3.59
2 000	79.00	30.28	18.57	13.43	10.60	5.07

TABLE G.22 Capital Costs Attributed to Gas – Area 4 – Economic Half Cycle

Gas In Place to Achieve a 15% Rate of Return GIP – 10^6 m^3 Gas Price – 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	20.27	7.72	4.73	3.42	2.69	1.29
1 000	27.23	10.39	6.45	4.66	3.65	1.76
1 500	33.89	12.89	8.01	5.76	4.51	2.16
2 000	46.74	17.64	10.93	7.90	6.19	2.96

TABLE G.23 Capital Costs Attributed to Gas – Area 4 – No Royalty Full Cycle

Gas In Place to Achieve a 15% Rate of Return GIP – 10^6 m^3 Gas Price – 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	33.37	12.70	7.87	5.73	4.48	2.14
1 000	47.29	18.13	11.11	8.03	6.31	3.05
1 500	60.77	23.02	14.18	10.22	8.10	3.89
2 000	86.24	32.65	20.15	14.48	11.46	5.52

TABLE G.24 Capital Costs Attributed to Gas – Area 4 – No Royalty Half Cycle

Gas In Place to Achieve a 15% Rate of Return GIP – 10^6 m^3 Gas Price – 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	21.66	8.32	5.13	3.74	2.92	1.39
1 000	29.59	11.25	6.95	5.02	3.94	1.89
1 500	36.65	13.81	8.66	6.26	4.88	2.35
2 000	50.03	19.09	11.85	8.56	6.72	3.23

TABLE G.25 Capital Costs Attributed to Gas — Area 5 — Commercial Full Cycle

Gas In Place to Achieve a 15% Rate of Return GIP — 10^6 m^3 Gas Price — 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	41.75	16.41	10.35	7.52	5.93	2.88
1 000	59.08	23.22	14.65	10.63	8.38	4.08
1 500	75.62	29.72	18.75	13.61	10.74	5.22
2 000	106.62	41.90	26.44	19.19	15.14	7.37
2 500	130.15	51.15	32.28	23.43	18.48	8.98
3 000	162.07	63.69	40.19	29.17	23.01	11.18
3 500	225.68	88.69	55.97	40.62	32.04	15.57

TABLE G.26 Capital Costs Attributed to Gas — Area 5 — Commercial Half Cycle

Gas In Place to Achieve a 15% Rate of Return GIP — 10^6 m^3 Gas Price — 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	26.43	10.35	6.47	4.76	3.76	1.82
1 000	35.45	14.06	8.86	6.38	5.02	2.47
1 500	43.86	17.24	10.89	7.86	6.20	3.05
2 000	59.70	23.46	14.93	10.88	8.53	4.16
2 500	71.58	28.37	17.83	13.02	10.28	4.98
3 000	87.52	34.68	21.72	15.88	12.48	6.08
3 500	120.51	47.39	29.79	21.78	17.15	8.35

TABLE G.27 Capital Costs Attributed to Gas – Area 5 – Economic Full Cycle

Gas In Place to Achieve a 15% Rate of Return GIP – 10^6 m^3 Gas Price – 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	25.22	9.81	6.14	4.43	3.47	1.67
1 000	35.27	13.71	8.57	6.14	4.84	2.33
1 500	44.62	17.39	10.81	7.79	6.13	2.95
2 000	62.05	24.41	15.03	10.86	8.53	4.16
2 500	75.49	29.67	18.35	13.28	10.41	5.06
3 000	94.00	36.63	22.69	16.37	12.80	6.24
3 500	129.77	50.55	31.37	22.79	17.83	8.62

TABLE G.28 Capital Costs Attributed to Gas – Area 5 – Economic Half Cycle

Gas In Place to Achieve a 15% Rate of Return GIP – 10^6 m^3 Gas Price – 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	16.53	6.43	4.01	2.90	2.28	1.09
1 000	21.74	8.45	5.26	3.81	2.98	1.45
1 500	26.47	10.36	6.43	4.65	3.63	1.75
2 000	35.72	13.97	8.64	6.30	4.90	2.37
2 500	42.30	16.66	10.28	7.48	5.86	2.82
3 000	51.38	21.10	12.48	9.08	7.13	3.43
3 500	70.41	27.53	17.15	12.41	9.70	4.69

TABLE G.29 Capital Costs Attributed to Gas – Area 5 – No Royalty Full Cycle

Gas In Place to Achieve a 15% Rate of Return GIP – 10^6 m^3 Gas Price – 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	27.26	10.63	6.60	4.78	3.75	1.81
1 000	38.28	14.77	9.22	6.68	5.26	2.51
1 500	48.40	18.68	11.72	8.47	6.65	3.29
2 000	67.17	26.34	16.31	11.83	9.28	4.48
2 500	81.99	32.15	19.78	14.32	11.26	5.47
3 000	102.10	39.55	24.47	17.67	13.94	6.73
3 500	139.92	54.84	33.85	24.6	19.41	9.25

TABLE G.30 Capital Costs Attributed to Gas – Area 5 – No Royalty Half Cycle

Gas In Place to Achieve a 15% Rate of Return GIP – 10^6 m^3 Gas Price – 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	17.74	6.89	4.30	3.11	2.44	1.17
1 000	23.40	9.16	5.67	4.14	3.23	1.55
1 500	28.74	11.19	6.88	5.03	3.91	1.89
2 000	38.38	14.93	9.33	6.72	5.33	2.56
2 500	45.55	17.83	11.06	8.00	6.35	3.02
3 000	55.10	21.56	13.45	9.72	7.70	3.70
3 500	76.73	29.79	18.44	13.43	10.54	5.06

TABLE G.31 Capital Costs Attributed to Gas – Area 6 – Commercial Full Cycle

Gas In Place to Achieve a 15% Rate of Return GIP – 10^6 m^3 Gas Price – 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	75.75	29.54	18.56	13.64	10.61	5.15
1 000	112.11	43.72	27.47	20.19	15.71	7.62
1 500	171.53	66.90	42.01	30.87	24.02	11.65

TABLE G.32 Capital Costs Attributed to Gas – Area 6 – Commercial Half Cycle

Gas In Place to Achieve a 15% Rate of Return GIP – 10^6 m^3 Gas Price – 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	55.30	21.59	13.56	9.85	7.80	3.71
1 000	80.16	31.17	19.62	14.24	11.27	5.49
1 500	120.07	46.83	29.41	21.35	16.98	8.23

TABLE G.33 Capital Costs Attributed to Gas – Area 6 – Economic Full Cycle

Gas In Place to Achieve a 15% Rate of Return GIP – 10^6 m^3 Gas Price – 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	47.72	18.26	11.29	8.18	6.36	3.07
1 000	68.95	26.45	16.37	11.77	9.19	4.44
1 500	103.78	39.79	24.53	17.84	13.88	6.70

TABLE G.34 Capital Costs Attributed to Gas — Area 6 — Economic Half Cycle

Gas In Place to Achieve a 15% Rate of Return GIP — 10^6 m^3 Gas Price — 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	35.60	13.71	8.48	6.16	4.77	2.31
1 000	50.45	19.39	12.00	8.63	6.73	3.25
1 500	74.62	28.65	17.67	12.86	9.96	4.80

TABLE G.35 Capital Costs Attributed to Gas — Area 6 — No Royalty Full Cycle

Gas In Place to Achieve a 15% Rate of Return GIP — 10^6 m^3 Gas Price — 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	49.24	19.70	12.20	8.86	6.89	3.33
1 000	75.11	28.59	17.71	12.89	9.97	4.82
1 500	112.35	43.40	26.86	19.38	15.09	7.30

TABLE G.36 Capital Costs Attributed to Gas — Area 6 — No Royalty Half Cycle

Gas In Place to Achieve a 15% Rate of Return GIP — 10^6 m^3 Gas Price — 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	38.63	14.77	9.17	6.65	5.15	2.50
1 000	54.37	20.77	12.87	9.31	7.29	3.53
1 500	79.76	30.53	18.87	13.72	10.8	5.15

TABLE G.37 Capital Costs Attributed to Gas – Area 7 – Commercial Full Cycle

Gas In Place to Achieve a 15% Rate of Return GIP – 10^6 m^3 Gas Price – 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	64.65	25.86	16.36	11.90	9.41	4.59
1 000	83.72	33.49	21.18	15.49	12.18	5.94
1 500	112.18	44.87	28.38	20.75	16.32	7.96
2 000	148.08	59.32	37.46	27.39	21.55	10.51
2 500	200.70	80.28	50.77	37.13	29.20	14.25
3 000	270.95	109.19	69.09	50.40	39.69	19.51

TABLE G.38 Capital Costs Attributed to Gas – Area 7 – Commercial Half Cycle

Gas In Place to Achieve a 15% Rate of Return GIP – 10^6 m^3 Gas Price – 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	39.44	16.65	9.96	7.24	5.69	2.78
1 000	48.14	19.09	12.14	8.87	6.95	3.39
1 500	60.58	24.23	15.37	11.22	8.86	4.32
2 000	76.71	31.10	19.55	14.22	11.25	5.51
2 500	100.35	40.14	25.09	18.46	14.65	7.12
3 000	131.95	52.84	33.33	24.26	19.24	9.40

TABLE G.39 Capital Costs Attributed to Gas – Area 7 – Economic Full Cycle

Gas In Place to Achieve a 15% Rate of Return GIP – 10^6 m^3 Gas Price – 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	39.76	15.74	9.83	7.13	5.59	2.70
1 000	50.65	19.93	12.56	9.04	7.07	3.43
1 500	67.31	27.70	16.71	12.12	9.48	4.57
2 000	88.11	35.09	21.92	15.84	12.47	6.00
2 500	118.41	46.96	29.30	21.27	16.66	8.03
3 000	158.51	62.86	39.29	28.45	22.35	10.84

TABLE G.40 Capital Costs Attributed to Gas — Area 7 — Economic Half Cycle

Gas In Place to Achieve a 15% Rate of Return GIP — 10^6 m^3 Gas Price — 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	25.21	9.96	6.21	4.53	3.52	1.70
1 000	30.14	11.89	7.41	5.37	4.24	2.03
1 500	37.47	14.81	9.31	6.73	5.31	2.55
2 000	47.09	18.66	11.65	8.44	6.59	3.18
2 500	60.21	23.68	14.85	10.84	8.53	4.11
3 000	78.58	31.16	19.43	14.09	11.05	5.34

TABLE G.41 Capital Costs Attributed to Gas — Area 7 — No Royalty Full Cycle

Gas In Place to Achieve a 15% Rate of Return GIP — 10^6 m^3 Gas Price — 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	42.76	16.94	10.60	7.69	6.01	2.91
1 000	54.84	21.60	13.48	9.80	7.70	3.68
1 500	72.92	28.61	17.84	13.01	10.21	4.94
2 000	95.51	37.46	23.40	17.18	13.48	6.44
2 500	128.05	50.58	31.51	22.88	18.06	8.63
3 000	171.78	68.01	42.27	30.75	24.25	11.65

TABLE G.42 Capital Costs Attributed to Gas — Area 7 — No Royalty Half Cycle

Gas In Place to Achieve a 15% Rate of Return GIP — 10^6 m^3 Gas Price — 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	26.96	10.67	6.66	4.82	3.79	1.83
1 000	32.23	12.81	8.01	5.81	4.56	2.19
1 500	40.38	15.93	10.01	7.24	5.64	2.73
2 000	50.35	19.84	12.36	8.99	7.12	3.41
2 500	64.22	25.69	15.86	11.54	9.03	4.42
3 000	83.99	33.60	20.86	15.04	11.87	5.77

TABLE G.43 Capital Costs Attributed to Gas — Area 8 — Commercial Full Cycle

Gas In Place to Achieve a 15% Rate of Return GIP — 10^6 m^3 Gas Price — 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	75.50	28.99	18.12	13.14	10.34	5.02
1 000	114.76	44.07	27.54	19.97	15.72	7.63
1 500	157.22	60.37	37.73	27.36	21.54	10.46
2 000	202.50	77.76	48.60	35.24	27.74	13.47
2 500	240.98	92.54	57.83	41.93	33.01	16.03
3 000	315.68	121.22	75.76	54.93	43.25	20.99

TABLE G.44 Capital Costs Attributed to Gas — Area 8 — Commercial Half Cycle

Gas In Place to Achieve a 15% Rate of Return GIP — 10^6 m^3 Gas Price — 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	42.58	16.23	10.19	7.44	5.81	2.83
1 000	57.04	21.80	13.54	9.98	7.77	3.79
1 500	71.69	27.36	17.14	12.42	9.75	4.72
2 000	87.68	34.02	21.26	15.29	12.05	5.83
2 500	101.21	39.04	24.58	17.71	13.98	6.75
3 000	128.17	49.88	30.94	22.26	17.74	8.52

TABLE G.45 Capital Costs Attributed to Gas — Area 8 — Economic Full Cycle

Gas In Place to Achieve a 15% Rate of Return GIP — 10^6 m^3 Gas Price — 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	46.43	17.67	10.80	7.87	6.15	2.94
1 000	68.86	26.05	16.07	11.74	9.10	4.42
1 500	93.23	35.22	21.85	15.93	12.36	5.97
2 000	118.46	44.96	27.74	20.25	15.80	7.59
2 500	140.97	53.50	33.01	24.10	18.80	9.04
3 000	184.67	70.08	43.25	31.25	24.46	11.77

TABLE G.46 Capital Costs Attributed to Gas — Area 8 — Economic Half Cycle

Gas In Place to Achieve a 15% Rate of Return GIP — 10^6 m^3 Gas Price — 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	27.18	10.34	6.40	4.64	3.62	1.74
1 000	35.58	13.43	8.30	6.02	4.71	2.25
1 500	44.02	16.67	10.31	7.47	5.82	2.78
2 000	53.46	20.25	12.49	9.01	7.03	3.36
2 500	61.69	23.13	14.34	10.36	8.12	3.88
3 000	77.03	29.20	17.99	13.01	10.10	4.86

TABLE G.47 Capital Costs Attributed to Gas — Area 8 — No Royalty Full Cycle

Gas In Place to Achieve a 15% Rate of Return GIP — 10^6 m^3 Gas Price — 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	49.83	19.06	11.70	8.46	6.64	3.17
1 000	74.48	28.12	17.44	12.51	9.87	4.71
1 500	101.25	38.05	23.43	16.98	13.36	6.37
2 000	129.60	48.60	29.97	21.67	17.01	8.14
2 500	153.26	57.71	35.54	25.78	20.24	9.64
3 000	199.51	75.45	46.40	33.78	26.52	12.63

TABLE G.48 Capital Costs Attributed to Gas — Area 8 — No Royalty Half Cycle

Gas In Place to Achieve a 15% Rate of Return GIP — 10^6 m^3 Gas Price — 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	29.45	11.10	6.80	4.91	3.85	1.85
1 000	38.33	14.35	8.87	6.43	5.05	2.41
1 500	47.17	17.92	11.01	8.02	6.21	2.83
2 000	57.71	21.87	13.32	9.72	7.55	3.65
2 500	66.27	25.06	15.42	11.09	8.68	4.17
3 000	82.08	31.25	19.10	13.89	10.89	5.18

TABLE G.49 Capital Costs Attributed to Oil – Area 1 – Commercial Full Cycle

Gas In Place to Achieve a 15% Rate of Return GIP – 10^6 m^3 Gas Price – 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
3 000	22.11	9.54	6.10	4.46	3.52	1.72
3 500	22.11	9.54	6.10	4.46	3.52	1.72

TABLE G.50 Capital Costs Attributed to Oil – Area 1 – Economic Full Cycle

Gas In Place to Achieve a 15% Rate of Return GIP – 10^6 m^3 Gas Price – 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
3 000	16.07	6.99	4.48	3.29	2.59	1.27
3 500	16.07	6.99	4.48	3.29	2.59	1.27

TABLE G.51 Capital Costs Attributed to Oil – Area 1 – No Royalty Full Cycle

Gas In Place to Achieve a 15% Rate of Return GIP – 10^6 m^3 Gas Price – 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
3 000	17.44	7.56	4.82	3.53	2.78	1.36
3 500	17.44	7.56	4.82	3.53	2.78	1.36

TABLE G.52 Capital Costs Attributed to Oil – Area 2 – Commercial Full Cycle

Gas In Place to Achieve a 15% Rate of Return GIP – 10^6 m^3 Gas Price – 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
1 000	15.75	7.04	4.58	3.39	2.70	1.33
1 500	15.84	7.04	4.58	3.39	2.70	1.33
2 000	15.90	7.13	4.60	3.41	2.71	1.34
2 500	15.90	7.13	4.60	3.41	2.71	1.34
3 000	15.90	7.13	4.60	3.41	2.71	1.34
3 500	15.90	7.13	4.60	3.41	2.71	1.34
4 000	15.90	7.13	4.60	3.41	2.71	1.34
4 500	16.09	7.20	4.62	3.44	2.73	1.35
5 000	16.09	7.20	4.62	3.44	2.73	1.35
5 500	16.09	7.20	4.62	3.44	2.73	1.35

TABLE G.53 Capital Costs Attributed to Oil – Area 2 – Economic Full Cycle

Gas In Place to Achieve a 15% Rate of Return GIP – 10^6 m^3 Gas Price – 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
1 000	10.81	4.70	3.01	2.21	1.74	0.85
1 500	10.81	4.70	3.01	2.21	1.74	0.85
2 000	10.81	4.70	3.01	2.21	1.74	0.85
2 500	10.81	4.70	3.01	2.21	1.74	0.85
3 000	10.81	4.70	3.01	2.21	1.74	0.85
3 500	10.81	4.70	3.01	2.21	1.74	0.85
4 000	10.81	4.70	3.01	2.21	1.74	0.85
4 500	10.92	4.76	3.04	2.23	1.76	0.86
5 000	10.92	4.76	3.04	2.23	1.76	0.86
5 500	10.92	4.76	3.04	2.23	1.76	0.86

TABLE G.54 Capital Costs Attributed to Oil – Area 2 – No Royalty Full Cycle

Gas In Place to Achieve a 15% Rate of Return GIP – 10^6 m^3 Gas Price – 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
1 000	11.69	5.03	3.21	2.36	1.86	0.91
1 500	11.69	5.03	3.21	2.36	1.86	0.91
2 000	11.69	5.03	3.21	2.36	1.86	0.91
2 500	11.69	5.03	3.21	2.36	1.86	0.91
3 000	11.69	5.03	3.21	2.36	1.86	0.91
3 500	11.69	5.03	3.21	2.36	1.86	0.91
4 000	11.69	5.03	3.21	2.36	1.86	0.91
4 500	11.76	5.09	3.24	2.38	1.89	0.92
5 000	11.76	5.09	3.24	2.38	1.89	0.92
5 500	11.76	5.09	3.24	2.38	1.89	0.92

TABLE G.55 Capital Costs Attributed to Oil – Area 3 – Commercial Full Cycle

Gas In Place to Achieve a 15% Rate of Return GIP – 10^6 m^3 Gas Price – 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	8.10	3.20	1.99	1.47	1.14	0.56
1 000	8.10	3.20	1.99	1.47	1.14	0.56
1 500	14.10	5.60	3.50	2.60	2.00	0.98
2 000	14.10	5.60	3.50	2.60	2.00	0.98
2 500	14.10	5.60	3.50	2.60	2.00	0.98

TABLE G.56 Capital Costs Attributed to Oil – Area 3 – Economic Full Cycle

Gas In Place to Achieve a 15% Rate of Return GIP – 10^6 m^3 Gas Price – 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	6.04	2.36	1.46	1.06	0.83	0.40
1 000	6.04	2.36	1.46	1.06	0.83	0.40
1 500	9.87	3.85	2.39	1.73	1.36	0.65
2 000	9.87	3.85	2.39	1.73	1.36	0.65
2 500	9.87	3.85	2.39	1.73	1.36	0.65

TABLE G.57 Capital Costs Attributed to Oil — Area 3 — No Royalty Full Cycle

Gas In Place to Achieve a 15% Rate of Return GIP — 10^6 m^3 Gas Price — 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	6.84	2.65	1.64	1.20	0.94	0.45
1 000	6.84	2.65	1.64	1.20	0.94	0.45
1 500	10.70	4.15	2.59	1.87	1.47	0.70
2 000	10.70	4.15	2.59	1.87	1.47	0.70
2 500	10.70	4.15	2.59	1.87	1.47	0.70

TABLE G.58 Capital Costs Attributed to Oil — Area 4 — Commercial Full Cycle

Gas In Place to Achieve a 15% Rate of Return GIP — 10^6 m^3 Gas Price — 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	13.29	5.08	3.19	2.31	1.82	0.87
1 000	13.29	5.08	3.19	2.31	1.82	0.87
1 500	13.29	5.08	3.19	2.31	1.82	0.87
2 000	13.29	5.08	3.19	2.31	1.82	0.87

TABLE G.59 Capital Costs Attributed to Oil — Area 4 — Economic Full Cycle

Gas In Place to Achieve a 15% Rate of Return GIP — 10^6 m^3 Gas Price — 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	6.47	2.47	1.52	1.11	0.87	0.41
1 000	6.47	2.47	1.52	1.11	0.87	0.41
1 500	6.47	2.47	1.52	1.11	0.87	0.41
2 000	6.47	2.47	1.52	1.11	0.87	0.41

TABLE G.60 Capital Costs Attributed to Oil – Area 4 – No Royalty Full Cycle

Gas In Place to Achieve a 15% Rate of Return GIP – 10^6 m^3 Gas Price – 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	7.12	2.71	1.67	1.22	0.95	0.45
1 000	7.12	2.71	1.67	1.22	0.95	0.45
1 500	7.12	2.71	1.67	1.22	0.95	0.45
2 000	7.12	2.71	1.67	1.22	0.95	0.45

TABLE G.61 Capital Costs Attributed to Oil – Area 5 – Commercial Full Cycle

Gas In Place to Achieve a 15% Rate of Return GIP – 10^6 m^3 Gas Price – 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	12.67	4.95	3.10	2.26	1.78	0.86
1 000	12.67	4.95	3.10	2.26	1.78	0.86
1 500	12.67	4.95	3.10	2.26	1.78	0.86
2 000	12.67	4.95	3.10	2.26	1.78	0.86
2 500	12.75	5.01	3.12	2.28	1.80	0.87
3 000	12.75	5.01	3.12	2.28	1.80	0.87
3 500	12.75	5.01	3.12	2.28	1.80	0.87

TABLE G.62 Capital Costs Attributed to Oil – Area 5 – Economic Full Cycle

Gas In Place to Achieve a 15% Rate of Return GIP – 10^6 m^3 Gas Price – 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	8.56	3.34	2.07	1.50	1.18	0.57
1 000	8.56	3.34	2.07	1.50	1.18	0.57
1 500	8.56	3.34	2.07	1.50	1.18	0.57
2 000	8.56	3.34	2.07	1.50	1.18	0.57
2 500	8.59	3.36	2.08	1.51	1.18	0.57
3 000	8.59	3.36	2.08	1.51	1.18	0.57
3 500	8.59	3.36	2.08	1.51	1.18	0.57

TABLE G.63 Capital Costs Attributed to Oil — Area 5 — No Royalty Full Cycle

Gas In Place to Achieve a 15% Rate of Return GIP — 10^6 m^3 Gas Price — 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	9.27	3.62	2.24	1.63	1.27	0.61
1 000	9.27	3.62	2.24	1.63	1.27	0.61
1 500	9.27	3.62	2.24	1.63	1.27	0.61
2 000	9.27	3.62	2.24	1.63	1.27	0.61
2 500	9.32	3.63	2.25	1.64	1.28	0.62
3 000	9.32	3.63	2.25	1.64	1.28	0.62
3 500	9.32	3.63	2.25	1.64	1.28	0.62

TABLE G.64 Capital Costs Attributed to Oil — Area 6 — Commercial Full Cycle

Gas In Place to Achieve a 15% Rate of Return GIP — 10^6 m^3 Gas Price — 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	There is no light or medium oil in modified-PSAC Area 6.					

TABLE G.65 Capital Costs Attributed to Oil — Area 6 — Economic Full Cycle

Gas In Place to Achieve a 15% Rate of Return GIP — 10^6 m^3 Gas Price — 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	There is no light or medium oil in modified-PSAC Area 6.					

TABLE G.66 Capital Costs Attributed to Oil — Area 6 — No Royalty Full Cycle

Gas In Place to Achieve a 15% Rate of Return GIP — 10^6 m^3 Gas Price — 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	There is no light or medium oil in modified-PSAC Area 6.					

TABLE G.67 Capital Costs Attributed to Oil — Area 7 — Commercial Full Cycle

Gas In Place to Achieve a 15% Rate of Return GIP — 10^6 m^3 Gas Price — 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	22.24	8.92	5.59	4.07	3.21	1.56
1 000	22.24	8.92	5.59	4.07	3.21	1.56
1 500	22.24	8.92	5.59	4.07	3.21	1.56
2 000	22.24	8.92	5.59	4.07	3.21	1.56
2 500	22.48	8.99	5.66	4.11	3.25	1.57
3 000	22.48	8.99	5.66	4.11	3.25	1.57

TABLE G.68 Capital Costs Attributed to Oil — Area 7 — Economic Full Cycle

Gas In Place to Achieve a 15% Rate of Return GIP — 10^6 m^3 Gas Price — 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	15.13	6.01	3.75	2.72	2.13	1.03
1 000	15.13	6.01	3.75	2.72	2.13	1.03
1 500	15.13	6.01	3.75	2.72	2.13	1.03
2 000	15.13	6.01	3.75	2.72	2.13	1.03
2 500	15.25	6.02	3.75	2.73	2.15	1.03
3 000	15.25	6.02	3.75	2.73	2.15	1.03

TABLEG.69 Capital Costs Attributed to Oil — Area 7 — No Royalty Full Cycle

Gas In Place to Achieve a 15% Rate of Return GIP — 10^6 m^3 Gas Price — 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	16.36	6.47	4.04	2.94	2.30	1.11
1 000	16.36	6.47	4.04	2.94	2.30	1.11
1 500	16.36	6.47	4.04	2.94	2.30	1.11
2 000	16.36	6.47	4.04	2.94	2.30	1.11
2 500	16.45	6.52	4.07	2.95	2.30	1.11
3 000	16.45	6.52	4.07	2.95	2.30	1.11

TABLE G.70 Capital Costs Attributed to Oil – Area 8 – Commercial Full Cycle

Gas In Place to Achieve a 15% Rate of Return GIP – 10^6 m^3 Gas Price – 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	26.73	10.19	6.34	4.61	3.62	1.75
1 000	26.73	10.19	6.34	4.61	3.62	1.75
1 500	26.73	10.19	6.34	4.61	3.62	1.75
2 000	26.73	10.19	6.34	4.61	3.62	1.75

TABLE G.71 Capital Costs Attributed to Oil – Area 8 – Economic Full Cycle

Gas In Place to Achieve a 15% Rate of Return GIP – 10^6 m^3 Gas Price – 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	17.97	6.79	4.19	3.04	2.38	1.14
1 000	17.97	6.79	4.19	3.04	2.38	1.14
1 500	17.97	6.79	4.19	3.04	2.38	1.14
2 000	17.97	6.79	4.19	3.04	2.38	1.14

TABLE G.72 Capital Costs Attributed to Oil – Area 8 – No Royalty Full Cycle

Gas In Place to Achieve a 15% Rate of Return GIP – 10^6 m^3 Gas Price – 1991 Canadian Dollars						
Depth (m)	$1.00/GJ	$2.00/GJ	$3.00/GJ	$4.00/GJ	$5.00/GJ	$10.00/GJ
500	19.33	7.32	4.53	3.26	2.55	1.22
1 000	19.33	7.32	4.53	3.26	2.55	1.22
1 500	19.33	7.32	4.53	3.26	2.55	1.22
2 000	19.33	7.32	4.53	3.26	2.55	1.22

APPENDIX H MISCELLANEOUS MAPS OF ALBERTA

H.1 Figure 1 — Modified-PSAC Areas

The Board's study to determine the portion of Alberta's ultimate potential for gas which would be economically recoverable at various gas prices required division of the province into eight "modified-PSAC areas". These areas correspond to the Petroleum Services Association of Canada's (PSAC) areas as published in its annual well cost studies except that PSAC area 7 has been subdivided to include an area 8. Based on comments from industry, the Board believes the drilling costs are somewhat different in area 8 than in the rest of PSAC's area 7.

H.2 Figure 2 — Gas and Oil Areas

The Board's study of ultimate potential for gas in place, as described in Chapter 3, identified some 112 gas play areas in 36 stratigraphic intervals. Some 20 oil plays have also been identified in 14 intervals. The Board's most recent study of oil potential was done using a different methodology than for gas and the oil areas have been identified strictly for purposes of the gas study. Consequently, the oil area identification was done in a more cursory fashion than was the gas play area work. Figure 2 is a compilation of both the gas and oil play areas and is intended to indicate the areas of the province which hold gas, oil, or both gas and oil potential.

The small areas of north-central Alberta which indicate only oil resources will actually have some small amounts of solution gas. However, the volumes are very small and would not likely exceed field usage requirements in sufficient quantities to become a viable source of marketable gas.

H.3 Figure 3 — Number of Gas Zones

The section-by-section analysis in Step two of the economic analysis methodology (see Chapter 5, Section 5.4) determines how many gas zones underlie each section of the province. This map shows the number of gas zones on a township basis. The township is the lowest level of detail considered in the identification of gas play areas such that all sections in a particular township are assumed to have the same number of zones.

H.4 Figure 4 — Number of Oil Zones

This map is generated in exactly the same way as Figure 3 except that it pertains to oil rather than gas.

H.5 Figure 5 — Deepest Formation

This map was generated in the same way as Figure 3 except that this map shows the deepest zone in each township rather than the number of zones.

H.6 Figure 6 — Deepest Well Depth

For each township in the province, all existing wells which have penetrated the deepest formation in the township are identified. The depths of all such wells are averaged to determine the average depth of wells drilled to the deepest formation in this township. For townships where no wells have been drilled to the deepest formation, the surrounding townships are scanned to arrive at an estimate of the deepest well depth for the township.

H.7 Figure 7 — Undrilled Sections

This map indicates the number of undrilled sections in each township of the province. While some townships indicate that there are no undrilled sections, the township may still hold some potential for future gas resources in sections where the well(s) have not been drilled to the deepest formation.

Test holes, bitumen wells and some other well categories have not been considered in generating this map.

H.8 Figure 8 — GIP per Section

The future gas in place per section shown in this map has been generated assuming that the total future gas in each play area will be distributed evenly throughout all sections in the play area. While this assumption is reasonable for purposes of the macroscopic analysis being done in this study, specific sections cannot be expected to contain those volumes shown on the map.

Where there are one or more undrilled sections in a township, the map reflects the future gas in those sections. Where no undrilled sections exist, the map reflects the section with the maximum future gas in place.

H.9 Figure 9 — OIP per Section

This map is generated in the same way as Figure 8 except that it is for oil rather than gas. Of course the same caveats apply to using this map on a detailed basis as those pointed out for Figure 8.

H.10 Figure 10 — Gas Price

This map shows the gas price required to provide for economic recovery of gas in the undrilled sections of each township. Where no undrilled sections are present in a township, the gas price reflects that required for the section with the most future gas potential.

The data used to create this map is subject to all the caveats identified for this study in Chapter 5, Section 5.5. The map is intended to provide a broad overview of the gas price required to undertake gas ventures in Alberta and the reader is cautioned against use of the map on a specific section or township basis.

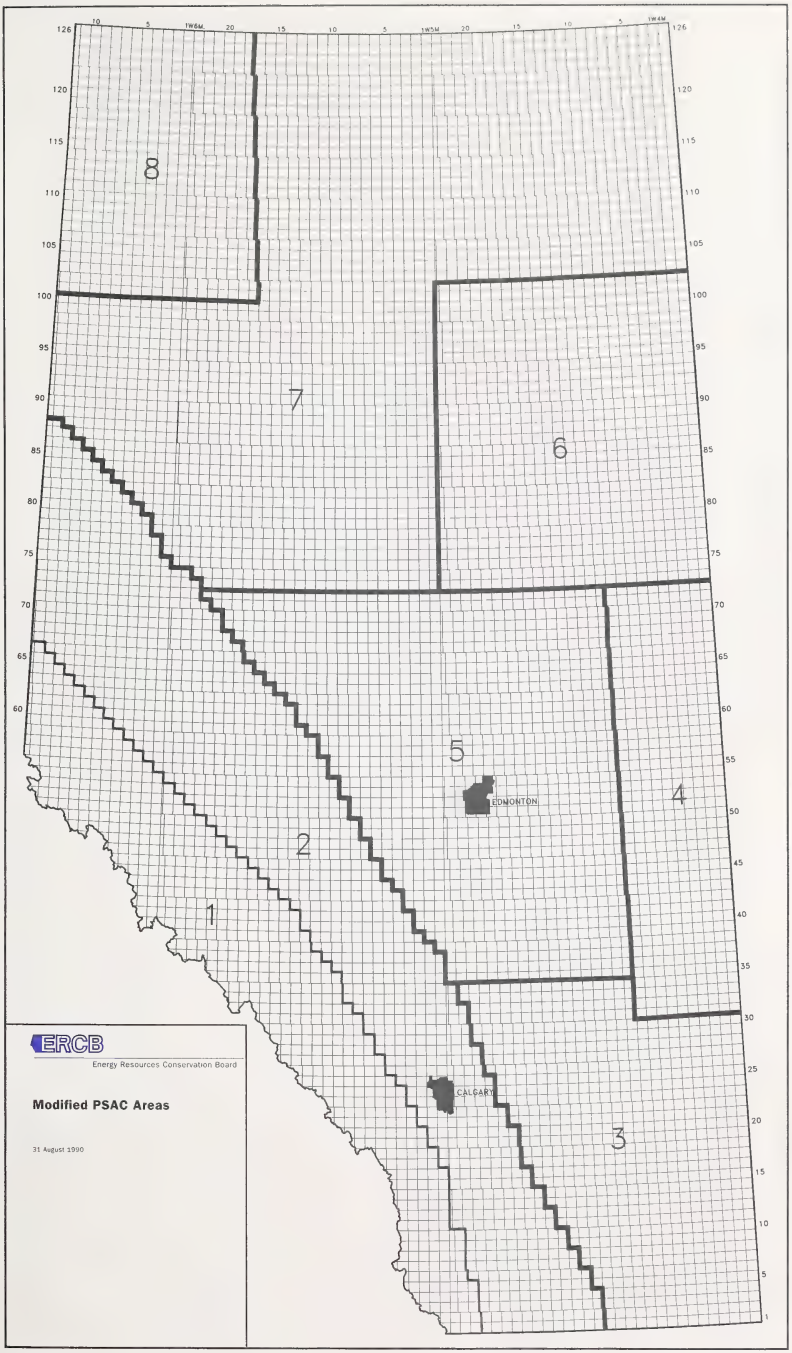

8
7
6
5
4
2
1
3
EDMONTON
CALGARY
ERCB
Energy Resources Conservation Board
Modified PSAC Areas
31 August 1990

FIGURE 1

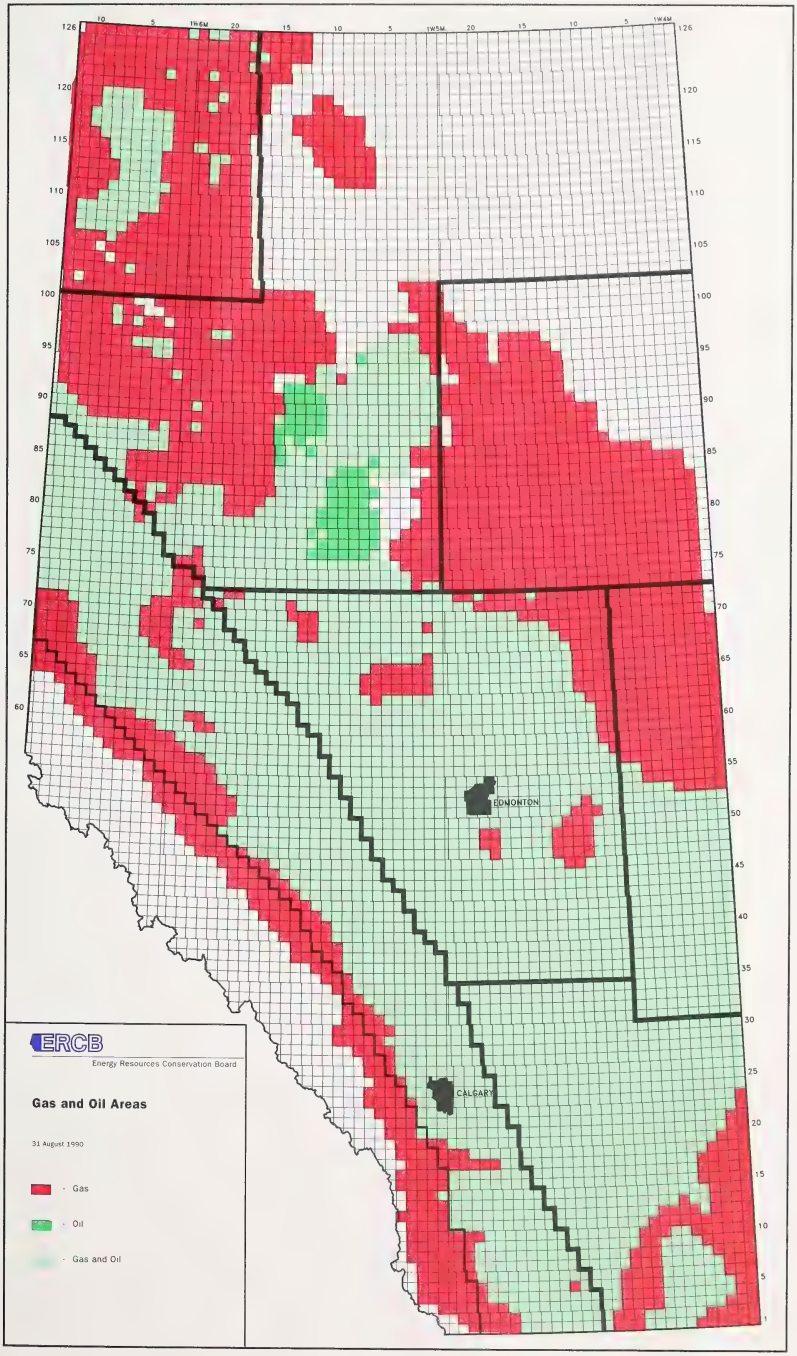

ERCB
Energy Resources Conservation Board
Gas and Oil Areas
31 August 1990
Gas
Oil
Gas and Oil
EDMONTON
CALGARY

FIGURE 2

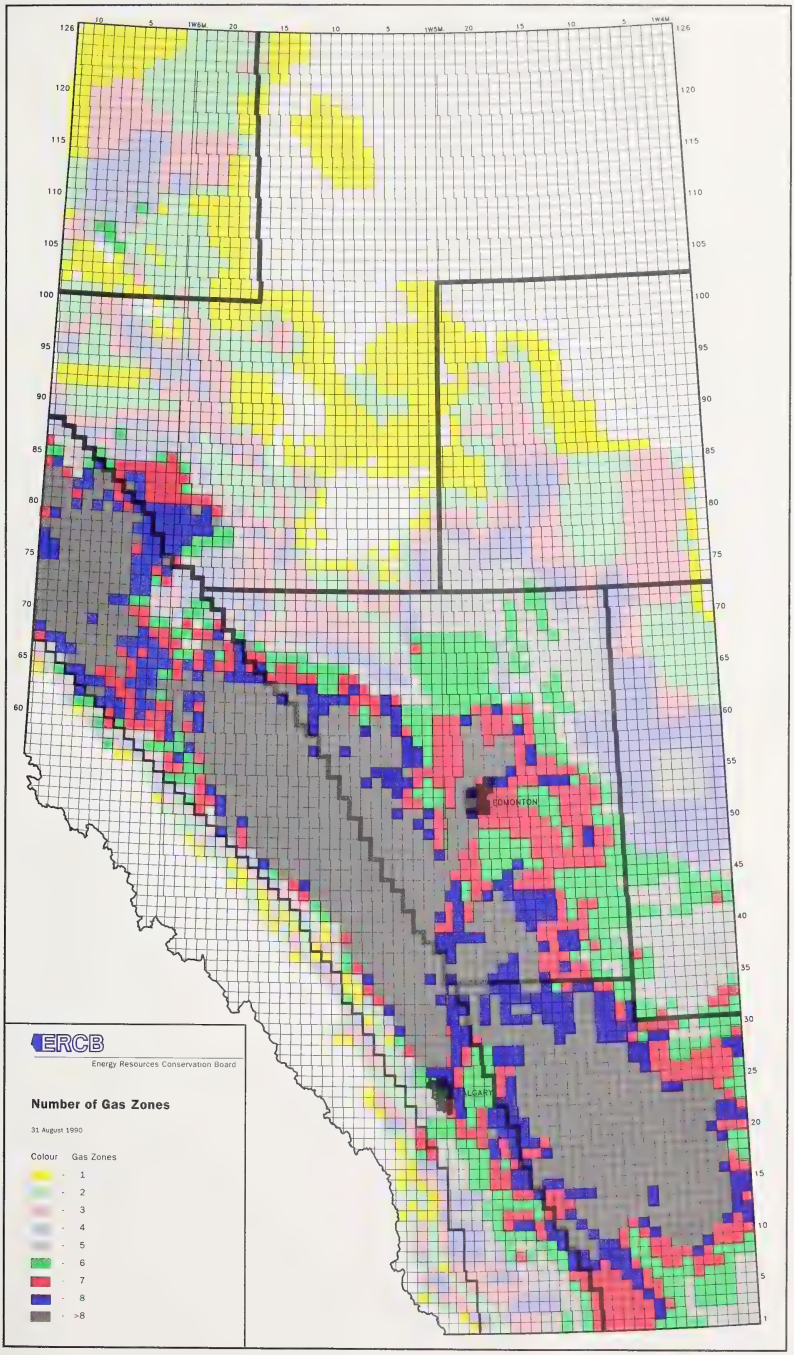

ERCB
Energy Resources Conservation Board
Number of Gas Zones
31 August 1990
Colour Gas Zones
1
2
3
4
5
6
7
8
>8
EDMONTON
CALGARY

FIGURE 3

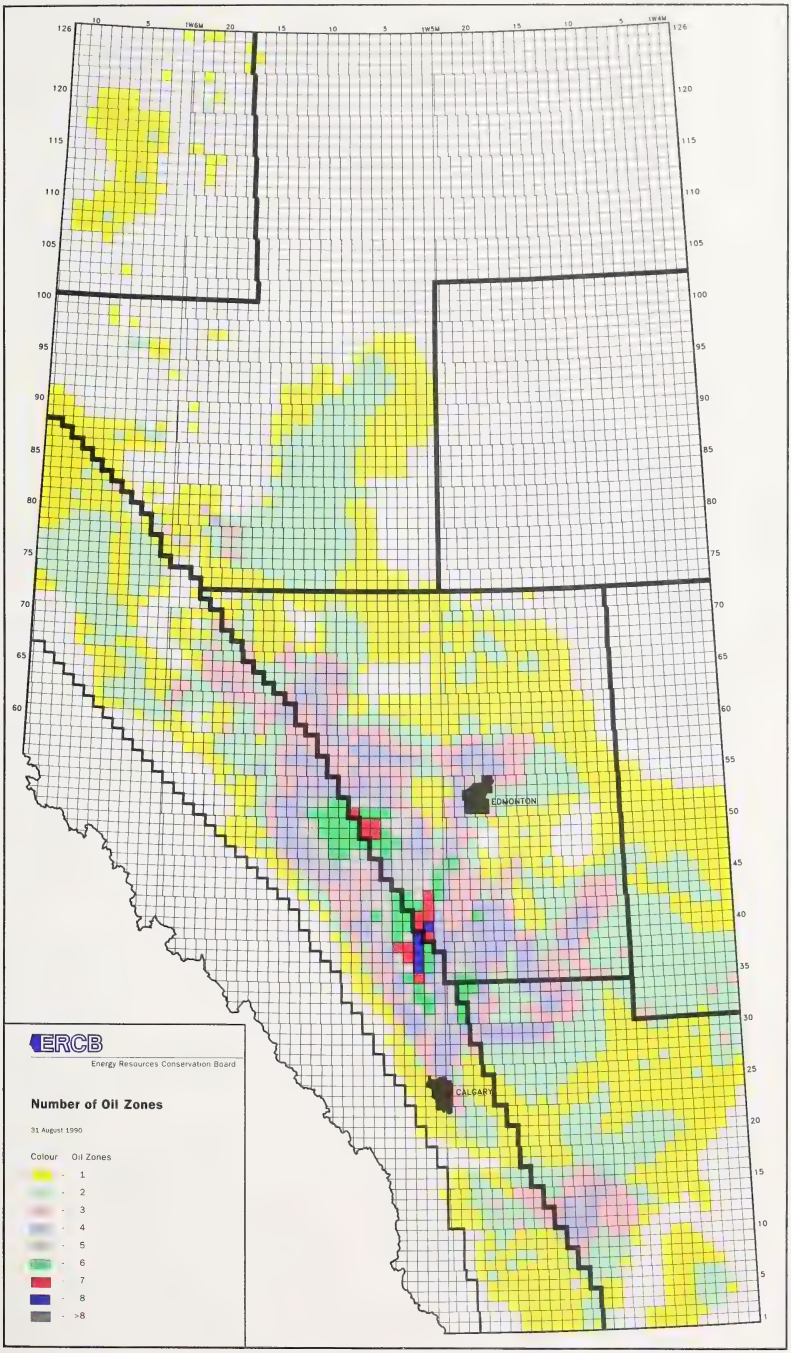

ERCB
Energy Resources Conservation Board
Number of Oil Zones
31 August 1990
Colour Oil Zones
1
2
3
4
5
6
7
8
>8
EDMONTON
CALGARY

FIGURE 4

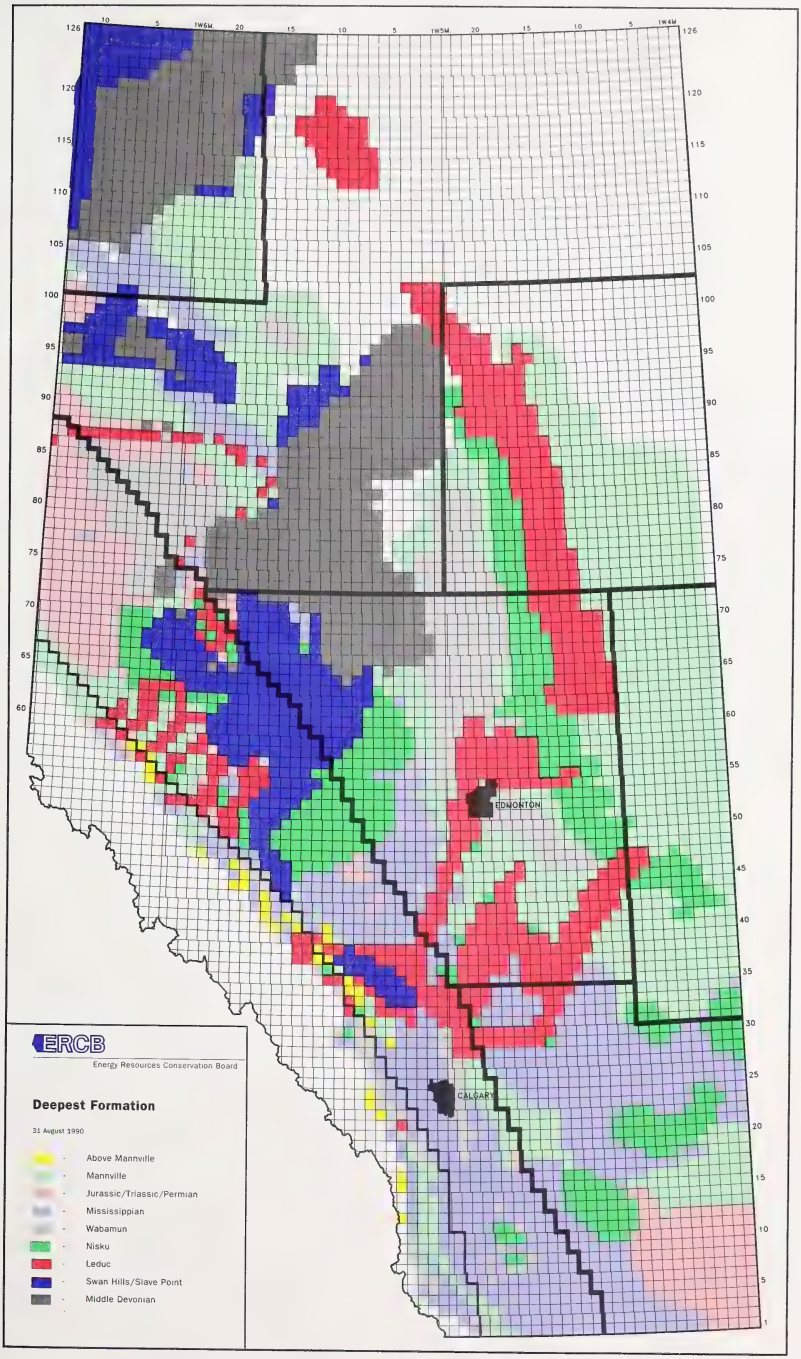

ERCB
Energy Resources Conservation Board
Deepest Formation
31 August 1990
Above Mannville
Mannville
Jurassic/Triassic/Permian
Mississippian
Wabamun
Nisku
Leduc
Swan Hills/Slave Point
Middle Devonian
EDMONTON
CALGARY

FIGURE 5

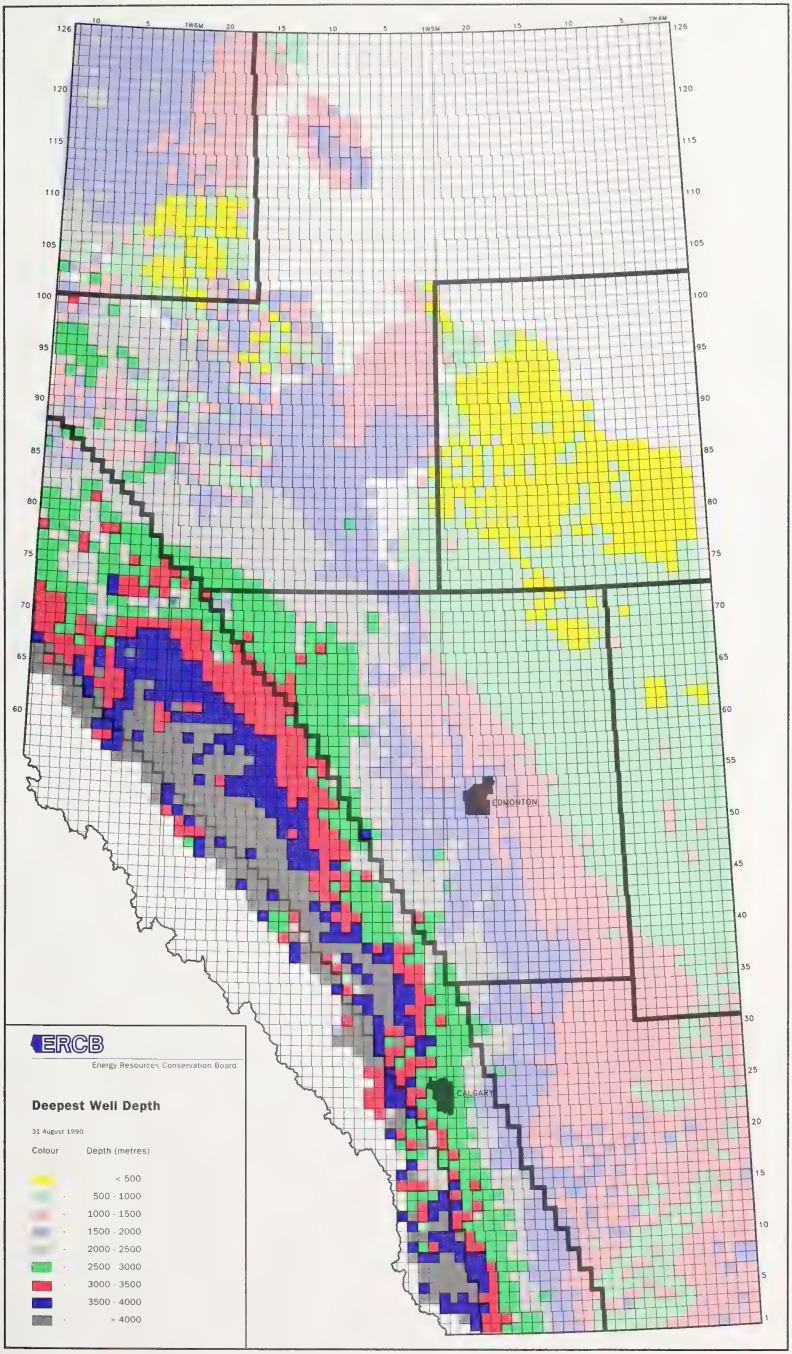

ERCB
Energy Resources Conservation Board
Deepest Well Depth
31 August 1990
Colour
Depth (metres)
< 500
500 - 1000
1000 - 1500
1500 - 2000
2000 - 2500
2500 - 3000
3000 - 3500
3500 - 4000
> 4000
EDMONTON
CALGARY

FIGURE 6

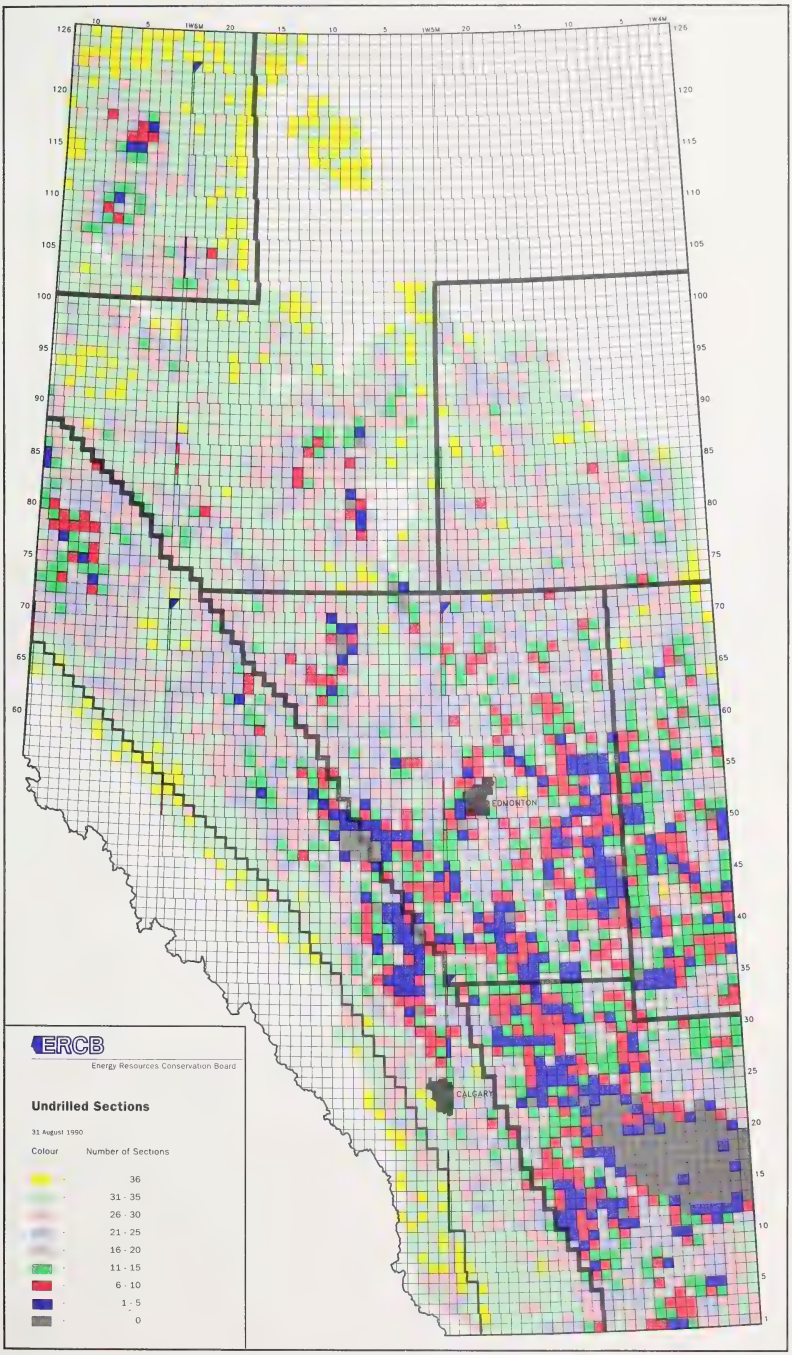

ERCB
Energy Resources Conservation Board
Undrilled Sections
31 August 1990
Colour
Number of Sections
36
31 - 35
26 - 30
21 - 25
16 - 20
11 - 15
6 - 10
1 - 5
0
EDMONTON
CALGARY

FIGURE 7

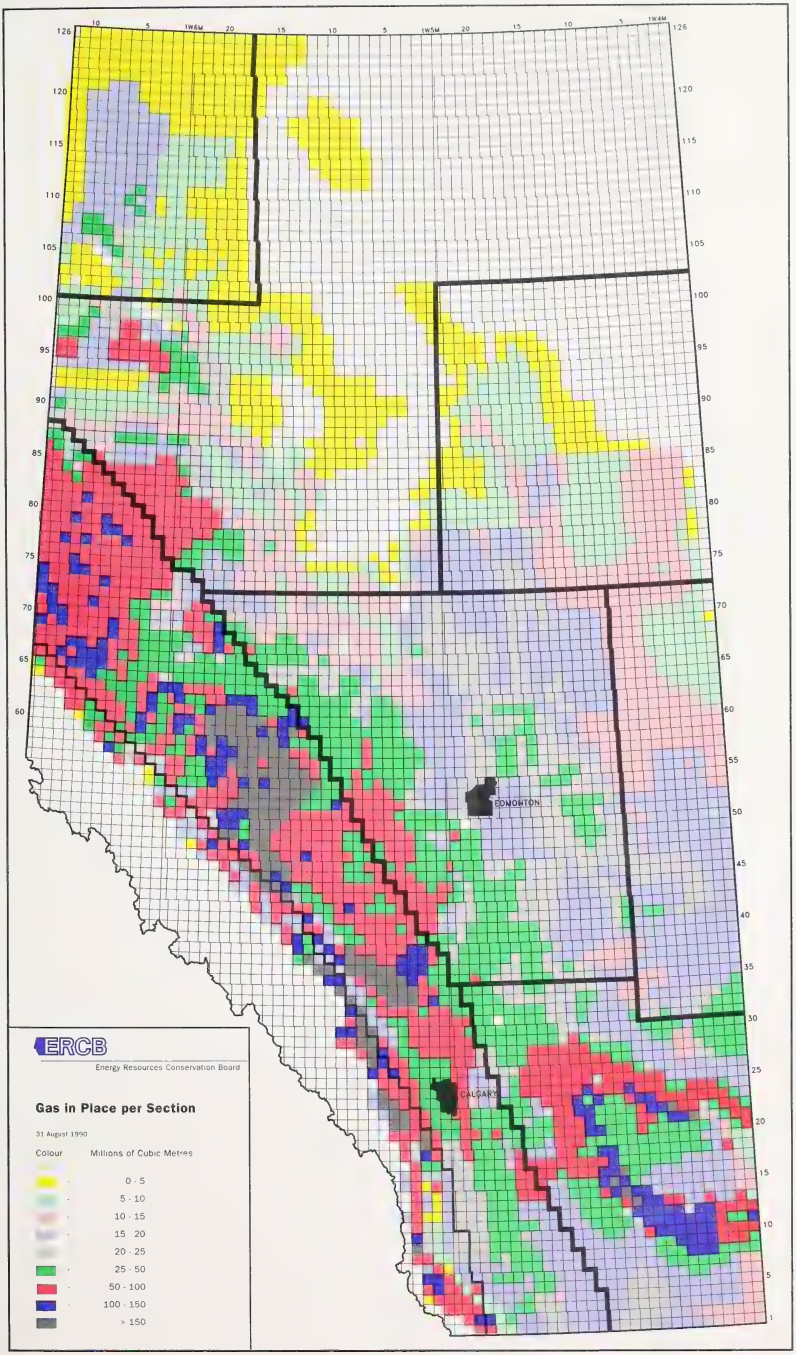

ERCB
Energy Resources Conservation Board
Gas in Place per Section
31 August 1990
Colour
Millions of Cubic Metres
0 - 5
5 - 10
10 - 15
15 - 20
20 - 25
25 - 50
50 - 100
100 - 150
> 150
EDMONTON
CALGARY

FIGURE 8

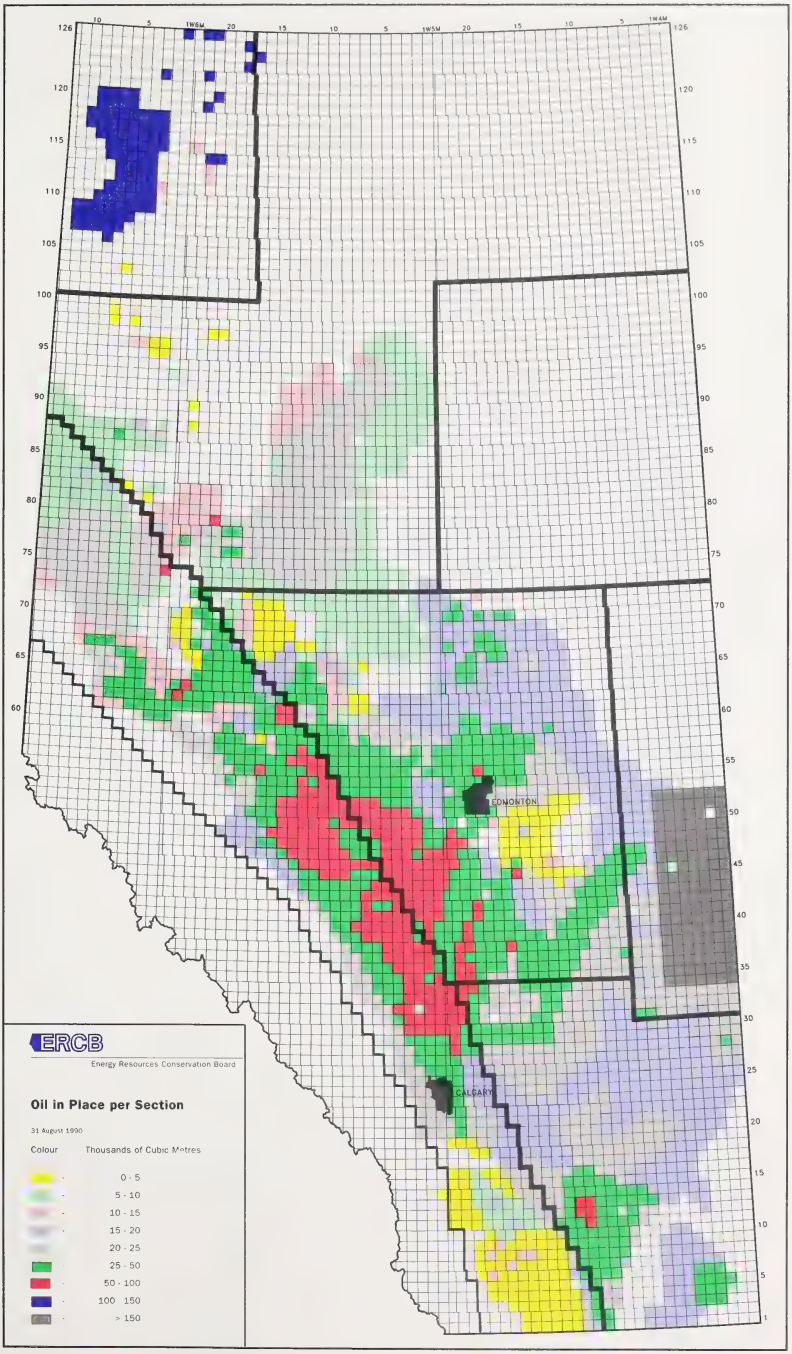

ERCB
Energy Resources Conservation Board
Oil in Place per Section
31 August 1990
Colour
Thousands of Cubic Metres
0 - 5
5 - 10
10 - 15
15 - 20
20 - 25
25 - 50
50 - 100
100 - 150
> 150
EDMONTON
CALGARY

FIGURE 9

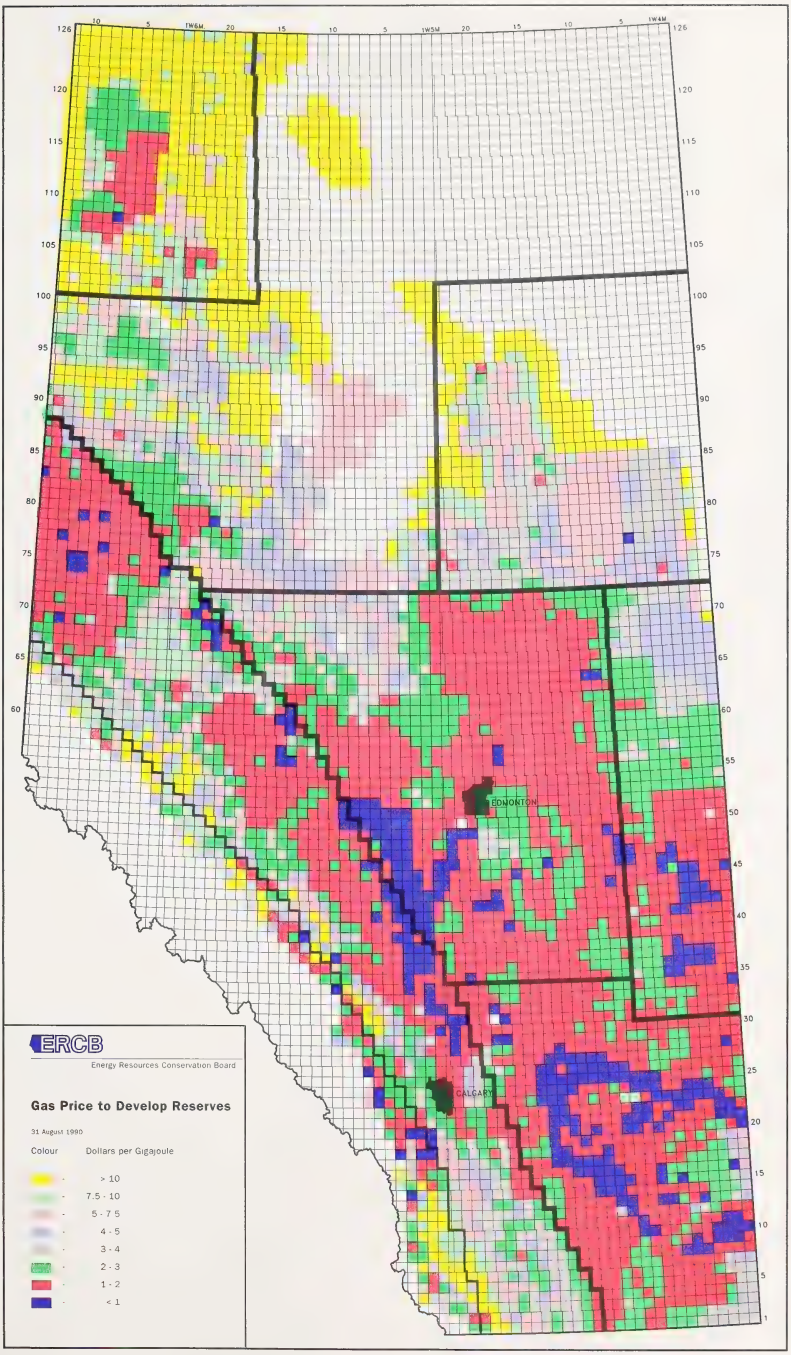

ERCB
Energy Resources Conservation Board
Gas Price to Develop Reserves
31 August 1990
Colour
Dollars per Gigajoule
> 10
7.5 - 10
5 - 7.5
4 - 5
3 - 4
2 - 3
1 - 2
< 1
EDMONTON
CALGARY

FIGURE 10

APPENDIX I CUMULATIVE GAS IN PLACE VS INCREASING GAS PRICE

TABLE I.1 GIP Added at Various Gas Prices – Commercial Full Cycle

Area	$1.00/GJ		$3.00/GJ		$5.00/GJ		$10.00/GJ		Estab.	Trend	Ult. Pot.
	10^9 m^3	%	10^9 m^3	%	10^9 m^3	%	10^9 m^3	%	10^9 m^3	10^9 m^3	10^9 m^3
1	49	11.33	287	65.86	394	90.35	421	96.61	437	436	873
2	162	7.76	1 536	73.63	1 876	89.92	2 048	98.19	2 174	2 086	4 260
3	179	38.62	427	92.12	454	98.05	462	99.86	948	463	1 411
4	11	8.24	94	71.60	121	92.39	131	99.39	224	132	356
5	52	9.93	446	84.66	496	94.12	523	99.11	1 216	527	1 743
6	2	1.65	14	11.18	71	57.09	114	91.71	153	124	277
7	3	0.92	141	39.63	227	63.95	325	91.76	140	355	495
8	1	1.09	35	37.59	37	39.37	65	70.30	117	93	210
Total	460	10.90	2 980	70.68	3 676	87.19	4 090	97.02	5 410	4 216	9 625

TABLE I.2 GIP Added at Various Gas Prices – Commercial Half Cycle

Area	$1.00/GJ		$3.00/GJ		$5.00/GJ		$10.00/GJ		Estab.	Trend	Ult. Pot.
	10^9 m^3	%	10^9 m^3	%	10^9 m^3	%	10^9 m^3	%	10^9 m^3	10^9 m^3	10^9 m^3
1	285	65.36	416	95.58	433	99.38	433	99.43	437	436	873
2	1 014	48.61	1 954	93.65	2 047	98.11	2 081	99.74	2 174	2 086	4 260
3	237	51.09	450	97.15	461	99.62	463	99.92	948	463	1 411
4	34	25.70	121	91.99	130	98.79	131	99.81	224	132	356
5	125	23.62	497	94.20	519	98.42	527	99.96	1 216	527	1 743
6	4	2.91	49	38.95	104	83.33	116	92.70	153	124	277
7	10	2.86	231	65.25	310	87.34	339	95.51	140	355	495
8	3	3.41	39	41.52	63	68.26	75	81.02	117	93	210
Total	1 711	40.58	3 756	89.10	4 067	96.47	4 164	98.78	5 410	4 216	9 625

TABLE I.3 GIP Added at Various Gas Prices – Economic Full Cycle

Area	$1.00/GJ		$3.00/GJ		$5.00/GJ		$10.00/GJ		Estab.	Trend	Ult. Pot.
	10^9 m^3	%	10^9 m^3	%	10^9 m^3	%	10^9 m^3	%	10^9 m^3	10^9 m^3	10^9 m^3
1	139	31.90	399	91.52	415	95.20	433	99.43	437	436	873
2	679	32.56	1 898	90.97	2 023	96.99	2 074	99.41	2 174	2 086	4 260
3	252	54.52	454	98.02	462	99.79	463	99.92	948	463	1 411
4	46	35.27	121	92.35	130	98.79	131	99.99	224	132	356
5	131	24.80	500	94.72	519	98.45	527	99.96	1 216	527	1 743
6	4	3.49	69	55.47	110	88.43	118	94.48	153	124	277
7	8	2.21	217	61.15	307	86.54	338	95.41	140	355	495
8	5	5.64	36	39.20	58	62.91	71	75.99	117	93	210
Total	1 266	30.02	3 694	87.62	4 025	95.47	4 155	98.56	5 410	4 216	9 625

TABLE I.4 GIP Added at Various Gas Prices – Economic Half Cycle

Area	$1.00/GJ		$3.00/GJ		$5.00/GJ		$10.00/GJ		Estab.	Trend	Ult. Pot.
	10^9 m^3	%	10^9 m^3	%	10^9 m^3	%	10^9 m^3	%	10^9 m^3	10^9 m^3	10^9 m^3
1	394	90.38	433	99.38	433	99.43	435	99.85	437	436	873
2	1 517	72.70	2 048	98.16	2 076	99.51	2 085	99.94	2 174	2 086	4 260
3	327	70.70	460	99.45	463	99.90	463	99.95	948	463	1 411
4	55	41.52	129	98.27	131	99.57	131	100.00	224	132	356
5	327	61.95	519	98.48	525	99.63	527	99.98	1 216	527	1 743
6	6	4.76	99	79.61	114	91.89	123	98.64	153	124	277
7	93	26.16	306	86.37	336	94.81	352	99.37	140	355	495
8	8	8.79	61	65.95	69	74.06	81	87.31	117	93	210
Total	2 726	64.67	4 056	96.22	4 147	98.38	4 198	99.58	5 410	4 216	9 625

TABLE I.5 GIP Added at Various Gas Prices – No Royalty Full Cycle

Area	$1.00/GJ		$3.00/GJ		$5.00/GJ		$10.00/GJ		Estab.	Trend	Ult. Pot.
	10^9 m^3	%	10^9 m^3	%	10^9 m^3	%	10^9 m^3	%	10^9 m^3	10^9 m^3	10^9 m^3
1	117	26.95	393	90.14	410	94.16	433	99.43	437	436	873
2	558	26.76	1 878	90.02	2 010	96.37	2 072	99.32	2 174	2 086	4 260
3	240	51.88	452	97.55	462	99.73	463	99.92	948	463	1 411
4	44	33.75	118	90.04	130	98.49	131	99.77	224	132	356
5	112	21.15	495	93.78	517	98.06	527	99.89	1 216	527	1 743
6	4	3.34	62	49.87	106	85.31	117	94.24	153	124	277
7	7	2.09	209	58.86	298	84.02	338	95.34	140	355	495
8	4	3.96	35	38.20	53	57.16	69	74.76	117	93	210
Total	1 087	25.79	3 642	86.38	3 986	94.56	4 151	98.46	5 410	4 216	9 625

TABLE I.6 GIP Added at Various Gas Prices – No Royalty Half Cycle

Area	$1.00/GJ		$3.00/GJ		$5.00/GJ		$10.00/GJ		Estab.	Trend	Ult. Pot.
	10^9 m^3	%	10^9 m^3	%	10^9 m^3	%	10^9 m^3	%	10^9 m^3	10^9 m^3	10^9 m^3
1	381	87.49	433	99.38	433	99.43	435	99.85	437	436	873
2	1 456	69.78	2 044	98.01	2 073	99.35	2 085	99.93	2 174	2 086	4 260
3	303	65.38	457	98.76	463	99.90	463	99.93	948	463	1 411
4	53	40.23	128	97.65	131	99.48	131	100.00	224	132	356
5	291	55.09	517	97.97	525	99.48	527	99.98	1 216	527	1 743
6	6	4.42	89	71.58	114	91.41	122	97.79	153	124	277
7	74	20.95	299	84.42	336	94.67	351	98.88	140	355	495
8	8	8.13	61	65.56	68	73.75	80	86.64	117	93	210
Total	2 571	60.97	4 029	95.58	4 142	98.25	4 194	99.48	5 410	4 216	9 625

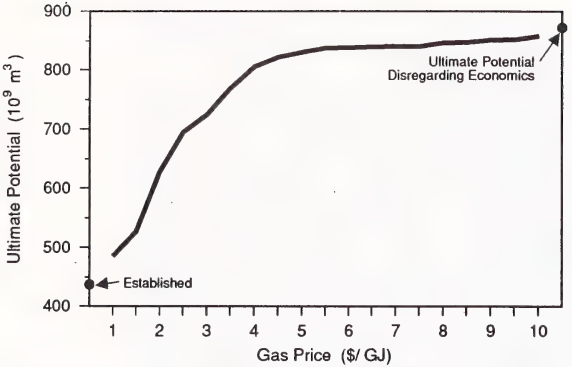


FIGURE I.1 GAS PRICE vs ULTIMATE POTENTIAL FOR GAS IN PLACE - AREA 1 Commercial Full Cycle Scenario

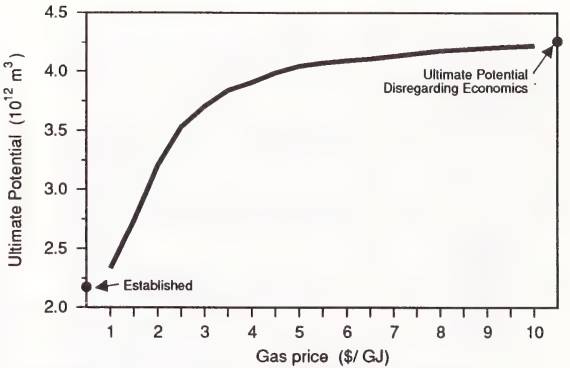


FIGURE I.2 GAS PRICE vs ULTIMATE POTENTIAL FOR GAS IN PLACE - AREA 2 Commercial Full Cycle Scenario

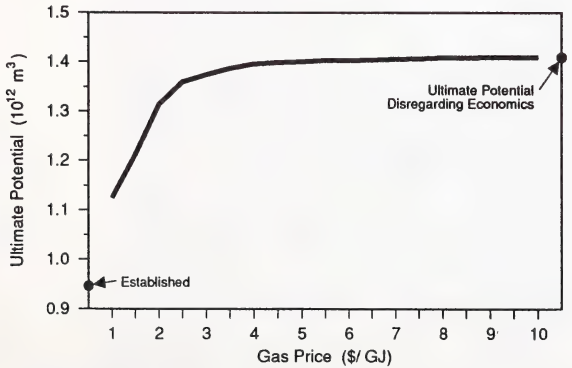


FIGURE I.3 GAS PRICE vs ULTIMATE POTENTIAL FOR GAS IN PLACE - AREA 3. Commercial Full Cycle Scenario

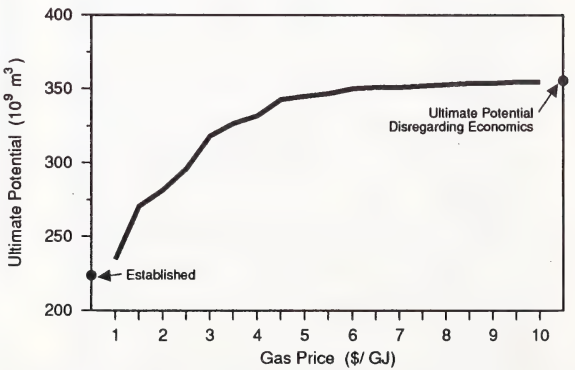


FIGURE I.4 GAS PRICE vs ULTIMATE POTENTIAL FOR GAS IN PLACE - AREA 4 Commercial Full Cycle Scenario

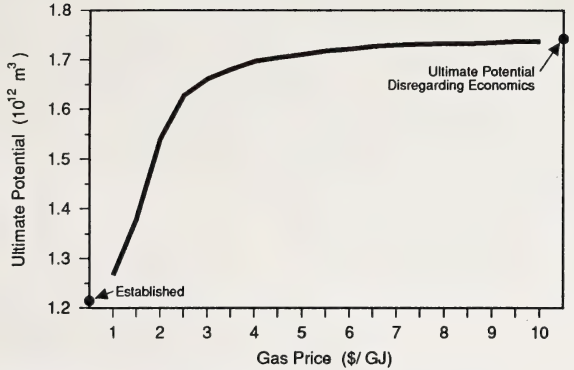


FIGURE I.5 GAS PRICE vs ULTIMATE POTENTIAL FOR GAS IN PLACE - AREA 5 Commercial Full Cycle Scenario

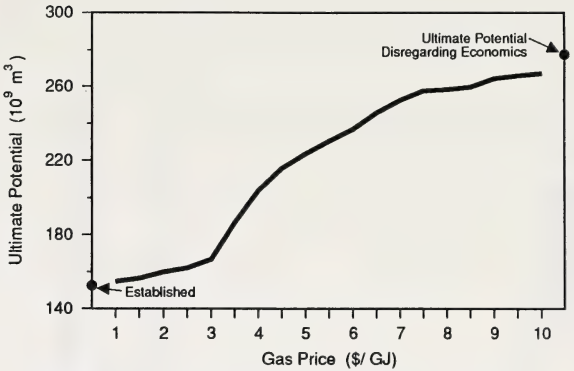


FIGURE I.6 GAS PRICE vs ULTIMATE POTENTIAL FOR GAS IN PLACE - AREA 6 Commercial Full Cycle Scenario

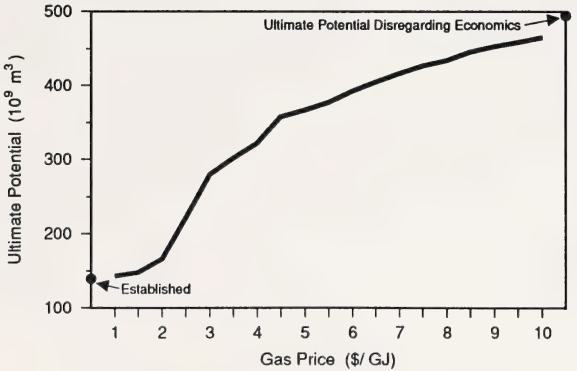


FIGURE I.7 GAS PRICE vs ULTIMATE POTENTIAL FOR GAS IN PLACE - AREA 7 Commercial Full Cycle Scenario

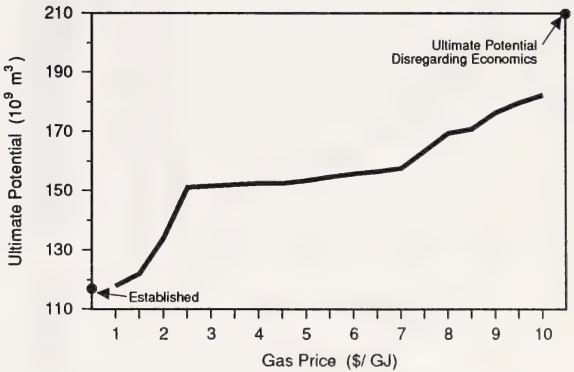


FIGURE I.8 GAS PRICE vs ULTIMATE POTENTIAL FOR GAS IN PLACE - AREA 8 Commercial Full Cycle Scenario

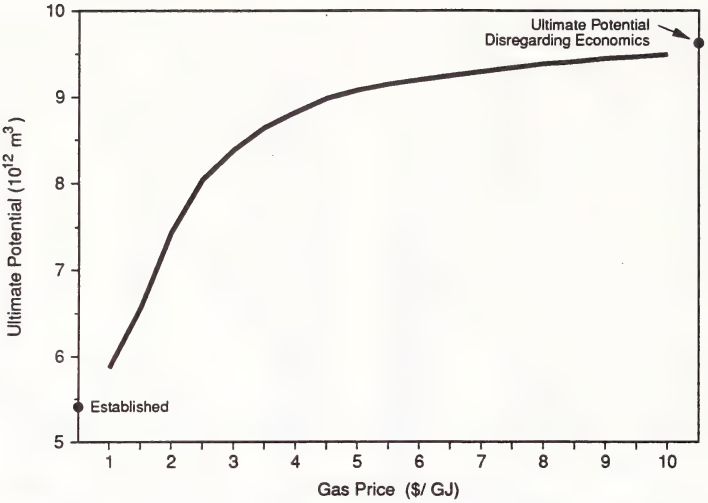


FIGURE I.9 GAS PRICE vs ULTIMATE POTENTIAL FOR GAS IN PLACE - ALBERTA
Commercial Full Cycle Scenario

APPENDIX J CUMULATIVE MARKETABLE GAS VS INCREASING GAS PRICE

TABLE J.1 IMG Added at Various Gas Prices – Commercial Full Cycle

Area	$1.00/GJ		$3.00/GJ		$5.00/GJ		$10.00/GJ		Estab.	Trend	Ult. Pot.
	10^9 m^3	%	10^9 m^3	%	10^9 m^3	%	10^9 m^3	%	10^9 m^3	10^9 m^3	10^9 m^3
1	25	10.62	147	62.93	205	87.84	223	95.44	230	234	464
2	88	7.52	854	72.65	1 047	89.08	1 151	97.93	1 180	1 175	2 355
3	122	38.63	291	92.27	310	98.14	315	99.87	660	315	975
4	7	8.27	62	71.91	79	92.43	85	99.42	153	85	238
5	31	9.48	282	85.04	313	94.28	329	99.18	736	332	1 068
6	1	1.69	9	11.34	45	57.65	72	92.15	97	79	176
7	2	0.92	92	39.02	152	63.98	219	92.35	101	236	337
8	1	0.99	20	36.02	21	37.81	39	68.93	68	56	124
Total	278	11.05	1 758	69.91	2 172	86.40	2 434	96.80	3 224	2 513	5 737

TABLE J.2 IMG Added at Various Gas Prices – Commercial Half Cycle

Area	$1.00/GJ		$3.00/GJ		$5.00/GJ		$10.00/GJ		Estab.	Trend	Ult. Pot.
	10^9 m^3	%	10^9 m^3	%	10^9 m^3	%	10^9 m^3	%	10^9 m^3	10^9 m^3	10^9 m^3
1	145	62.02	220	94.05	232	99.20	232	99.26	230	234	464
2	564	48.01	1 094	93.07	1 150	97.84	1 172	99.70	1 180	1 175	2 355
3	160	50.81	307	97.31	315	99.64	315	99.92	660	315	975
4	22	25.93	79	92.03	85	98.82	86	99.83	153	85	238
5	76	22.84	313	94.43	327	98.60	332	99.97	736	332	1 068
6	2	2.99	31	39.45	66	83.79	73	93.11	97	79	176
7	7	2.86	154	65.18	208	87.94	227	96.08	101	236	337
8	2	3.28	23	40.01	38	66.80	45	79.93	68	56	124
Total	979	38.91	2 221	88.34	2 420	96.25	2 482	98.73	3 224	2 513	5 737

TABLE J.3 IMG Added at Various Gas Prices – Economic Full Cycle

Area	$1.00/GJ		$3.00/GJ		$5.00/GJ		$10.00/GJ		Estab.	Trend	Ult. Pot.
	10^9 m^3	%	10^9 m^3	%	10^9 m^3	%	10^9 m^3	%	10^9 m^3	10^9 m^3	10^9 m^3
1	70	30.12	208	89.04	219	93.63	232	99.26	230	234	464
2	383	32.61	1 060	90.23	1 135	96.60	1 167	99.33	1 180	1 175	2 355
3	171	54.22	310	98.13	315	99.80	315	99.92	660	315	975
4	31	35.55	79	92.40	85	98.82	86	99.99	153	85	238
5	80	24.02	315	94.91	327	98.58	332	99.97	736	332	1 068
6	3	3.59	44	56.02	70	88.85	75	94.90	97	79	176
7	5	2.21	145	61.05	206	87.03	227	95.98	101	236	337
8	3	5.26	21	37.69	35	61.30	42	74.79	68	56	124
Total	746	29.66	2 182	86.80	2 392	95.12	2 477	98.50	3 224	2 513	5 737

TABLE J.4 IMG Added at Various Gas Prices – Economic Half Cycle

Area	$1.00/GJ		$3.00/GJ		$5.00/GJ		$10.00/GJ		Estab.	Trend	Ult. Pot.
	10^9 m^3	%	10^9 m^3	%	10^9 m^3	%	10^9 m^3	%	10^9 m^3	10^9 m^3	10^9 m^3
1	205	87.75	232	99.20	232	99.26	233	99.80	230	234	464
2	837	71.25	1 150	97.88	1 168	99.43	1 174	99.94	1 180	1 175	2 355
3	222	70.47	314	99.49	315	99.90	315	99.95	660	315	975
4	36	41.84	84	98.32	86	99.60	86	100.00	153	85	238
5	205	61.88	327	98.65	331	99.65	332	99.99	736	332	1 068
6	4	4.88	63	80.06	73	92.32	78	98.74	97	79	176
7	60	25.43	206	86.97	226	95.40	235	99.41	101	236	337
8	5	8.40	37	64.47	41	72.87	49	86.11	68	56	124
Total	1 575	62.63	2 413	95.98	2 472	98.31	2 503	99.54	3 224	2 513	5 737

TABLE J.5 IMG Added at Various Gas Prices – No Royalty Full Cycle

Area	$1.00/GJ		$3.00/GJ		$5.00/GJ		$10.00/GJ		Estab.	Trend	Ult. Pot.
	10^9 m^3	%	10^9 m^3	%	10^9 m^3	%	10^9 m^3	%	10^9 m^3	10^9 m^3	10^9 m^3
1	59	25.34	205	87.56	216	92.23	232	99.26	230	234	464
2	315	26.84	1 048	89.18	1 127	95.93	1 166	99.23	1 180	1 175	2 355
3	163	51.59	308	97.70	315	99.74	315	99.92	660	315	975
4	29	34.01	77	90.11	85	98.53	86	99.78	153	85	238
5	68	20.40	312	93.95	326	98.22	332	99.90	736	332	1 068
6	3	3.43	40	50.40	67	85.73	74	94.69	97	79	176
7	5	2.07	139	58.70	200	84.39	227	95.92	101	236	337
8	2	3.62	21	36.66	32	55.63	42	73.62	68	56	124
Total	644	25.62	2 150	85.49	2 367	94.14	2 474	98.40	3 224	2 513	5 737

TABLE J.6 IMG Added at Various Gas Prices – No Royalty Half Cycle

Area	$1.00/GJ		$3.00/GJ		$5.00/GJ		$10.00/GJ		Estab.	Trend	Ult. Pot.
	10^9 m^3	%	10^9 m^3	%	10^9 m^3	%	10^9 m^3	%	10^9 m^3	10^9 m^3	10^9 m^3
1	199	85.04	232	99.20	232	99.26	233	99.80	230	234	464
2	803	68.33	1 148	97.72	1 166	99.26	1 174	99.92	1 180	1 175	2 355
3	205	65.09	312	98.89	315	99.90	315	99.93	660	315	975
4	35	40.56	84	97.71	85	99.52	86	100.00	153	85	238
5	182	54.93	326	98.14	330	99.51	332	99.99	736	332	1 068
6	4	4.51	57	71.97	72	91.85	77	97.94	97	79	176
7	48	20.23	201	84.98	226	95.27	234	98.99	101	236	337
8	4	7.74	36	64.04	41	72.53	48	85.44	68	56	124
Total	1 480	58.87	2 396	95.30	2 468	98.17	2 500	99.45	3 224	2 513	5 737

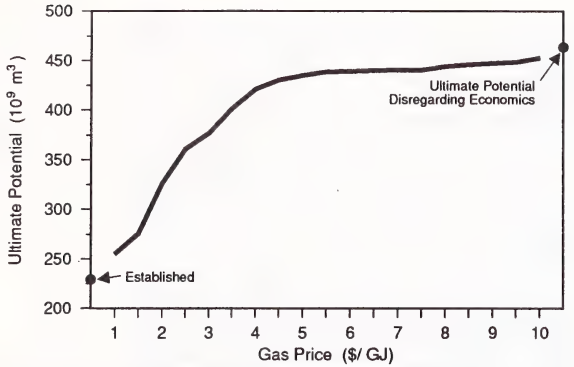


FIGURE J.1 GAS PRICE vs ULTIMATE POTENTIAL FOR MARKETABLE GAS - AREA 1 Commercial Full Cycle Scenario

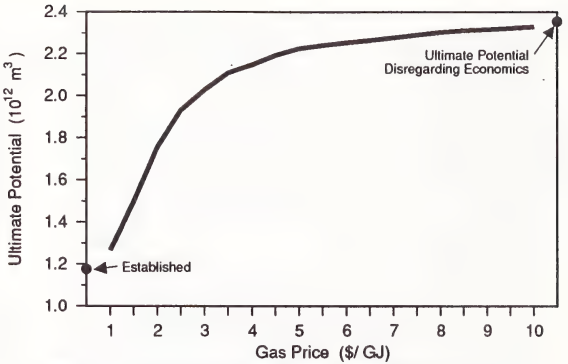


FIGURE J.2 GAS PRICE vs ULTIMATE POTENTIAL FOR MARKETABLE GAS - AREA 2 Commercial Full Cycle Scenario

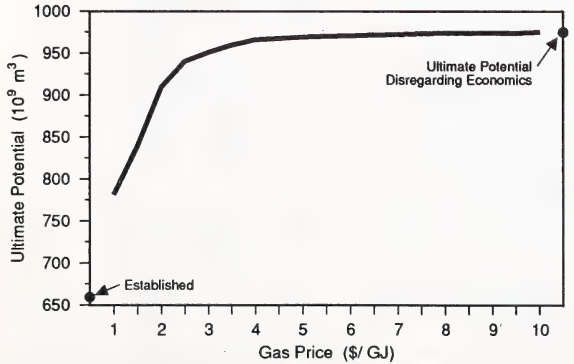


FIGURE J.3 GAS PRICE vs ULTIMATE POTENTIAL FOR MARKETABLE GAS - AREA 3 Commercial Full Cycle Scenario

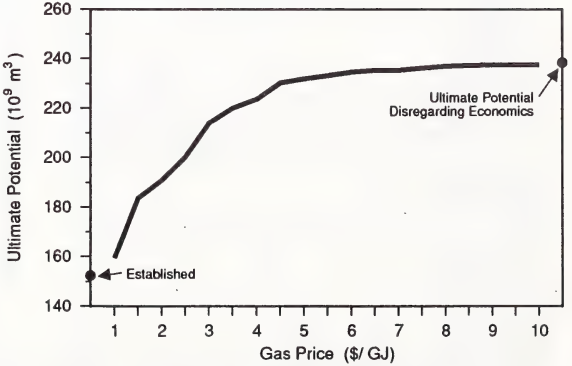


FIGURE J.4 GAS PRICE vs ULTIMATE POTENTIAL FOR MARKETABLE GAS - AREA 4 Commercial Full Cycle Scenario

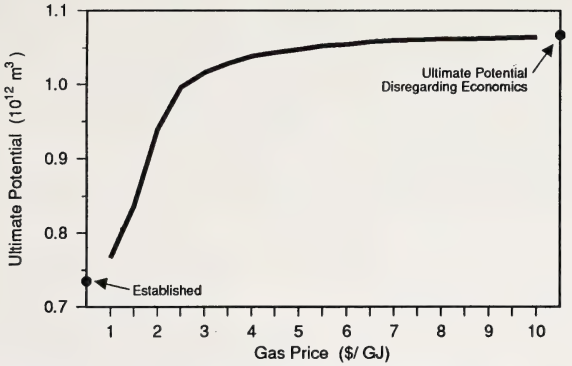


FIGURE J.5 GAS PRICE vs ULTIMATE POTENTIAL FOR MARKETABLE GAS - AREA 5
Commercial Full Cycle Scenario

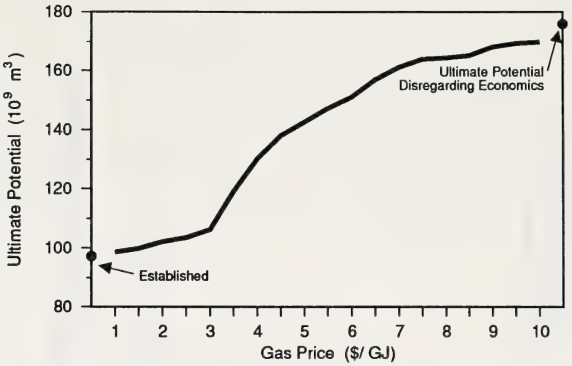


FIGURE J.6 GAS PRICE vs ULTIMATE POTENTIAL FOR MARKETABLE GAS - AREA 6
Commercial Full Cycle Scenario

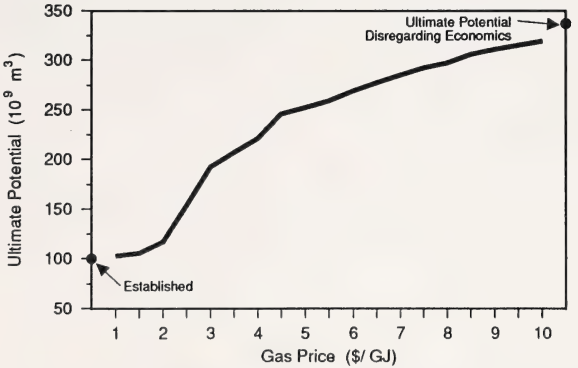


FIGURE J.7 GAS PRICE vs ULTIMATE POTENTIAL FOR MARKETABLE GAS - AREA 7
Commercial Full Cycle Scenario

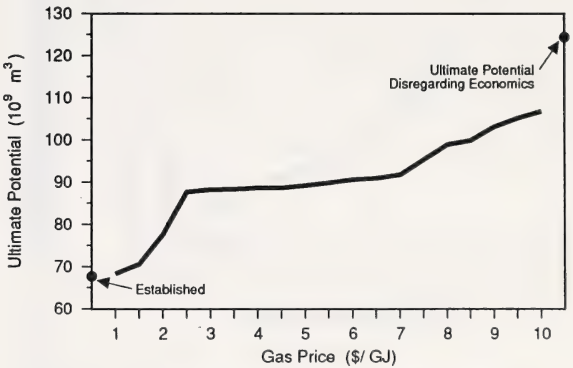


FIGURE J.8 GAS PRICE vs ULTIMATE POTENTIAL FOR MARKETABLE GAS - AREA 8
Commercial Full Cycle Scenario

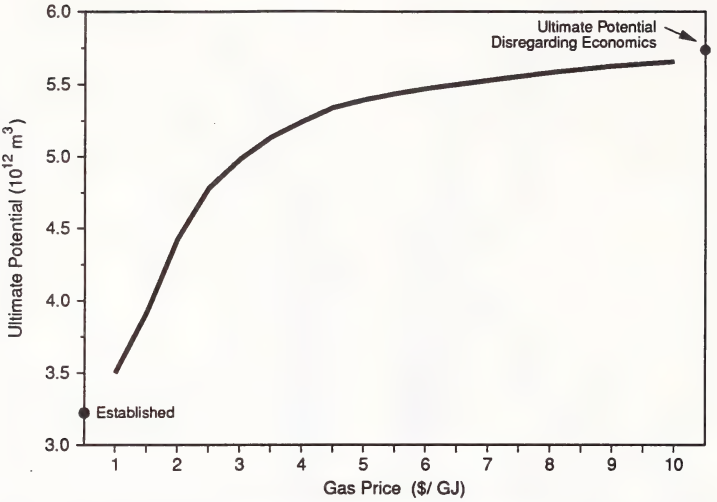


FIGURE J.9 GAS PRICE vs ULTIMATE POTENTIAL FOR MARKETABLE GAS - ALBERTA Commercial Full Cycle Scenario

APPENDIX K HISTORICAL RESERVES GROWTH

Many studies are done on the historical trends in reserve additions per well, reserve additions per metre of drilling, and cost per cubic metre to add reserves. Virtually all of these studies depend on a correlation of historical reserves growth versus drilling activity. They generally use "booked" reserve estimates as published by the ERCB, CPA, and others. Unfortunately, these reserve estimates undergo revisions as a result of individual reserve studies or changes in the methodology. Such revisions can be sizeable in either the positive or negative direction and may have little or nothing to do with the actual drilling activity which has taken place during the year. Consequently, there are anomalies in the historical data series and a study which depends on a reasonable correlation between reserve growth and drilling activity can be seriously affected.

In an attempt to solve this problem for its own analysis of reserves additions per section, the Board looked at several techniques for analyzing historical reserves growth. All these techniques are based on the assumption that the very best estimate of the reserves in any given pool is the most recent estimate. The question then remains as to when each portion of the pool's reserve is deemed to have been discovered. Problems created by reserve estimate revisions are thus avoided by disregarding what the reserve estimate may have been at any point in the past. The disadvantage of this approach is that the historical data may change with each new update of the reserves data. Therefore, any downstream analysis may have to be repeated.

The Board uses only one of these historical reserves growth analysis techniques in this report, that being the reserve additions per drilled section. However, the results for the other techniques are presented in the expectation that others may find them useful. Readers are left to decide which, if any, of these techniques are best suited to the particular studies they are undertaking.

The Board's various techniques for describing the pattern of historical reserves growth are discussed in the following sections. In all cases, where reserves are assumed to have been discovered by a particular well, the finished drilling date of the well is used as the discovery date for the reserve. Historical reserves growth on an ERCB booked basis as well as for the various alternative techniques are shown in Table K.1 and Figure K.1.

K.1 Booked Reserves

The Board studies Alberta's gas reserves on an ongoing basis and publishes annual updates of the data in report and computer file format. Analysis of a wide range of drilling, completion, testing and production data which is routinely submitted to the Board provides the impetus for much of the Board's reserves work. Many detailed studies of large pools, geological trends or categories of pools are done as deemed necessary. Additionally, reserves are reviewed as a result of various applications to the Board, particularly applications for removal of gas from the province.

As can be seen in Figure K.1, there are several anomalies in the historical data series. These anomalies result from major revisions to specific pools, pool categories or pool parameters. Some

examples include: major revisions to the large Bluesky Pool of northwestern Alberta and the Milk River Pool of southeastern Alberta, revisions to many Mississippian pools as a result of a trend study, and two iterations of revisions to most small pools in the province, affecting the recovery factors in one instance and the acreage assignments in the other.

Given that reserve estimation is far from an exact science, these types of revisions are unavoidable. The following techniques attempt to avoid the problems created by these revisions such that reserves growth versus drilling activity correlations are more reliable.

K.2 Discovery well

Probably the most simplistic approach to describing historical reserves growth is to assume that the entire reserve in each pool was discovered by the first well drilled in the pool. This approach "front-ends" reserve additions as exemplified by the discovery of the large southeastern Alberta shallow gas pools in the early 1900s.

K.3 All wells

This approach to reserves growth goes to the opposite extreme from the discovery well approach. It assumes that each well in the pool has discovered a portion of the reserve. In this technique, the Board has apportioned the reserves in a pool to all wells in the pool based on the net pay thickness in each well.

K.4 Exploratory wells

This technique apportions the reserves in a pool to all exploratory wells in the pool, again based on each well's pay thickness. If there are no exploratory wells in the pool, then the entire reserve is assigned to the discovery well for the pool.

K.5 Oldest wells

This approach assumes that the oldest 50% of the wells in the pool discovered the reserve. While the technique may be of questionable usefulness, it is interesting to note that it matches the booked reserves growth data fairly well.

K.6 Drilled Sections

The Board's geological and economic analyses have focused on a section-by-section analysis of the province's gas resources. The Board has carried this approach into the forecasting of reserves growth. Historical reserves growth has been analyzed on a section basis by picking one well in each

section as being the one that discovered the reserves in that section. The chosen well is the oldest well which penetrated the deepest currently drilled formation in the section. All other wells in the section are assumed to have been drilled as oil or gas development wells or for some other purpose than to discover or provide information on gas reserves.

Reserves in undrilled sections are dated by sorting the undrilled sections by reserve size and assigning, in chronological order, the dates from the drilled sections. This assumes that the better quality undrilled sections are discovered earlier in the pool life.

TABLE K.1 Reserves Growth Analysis Techniques

Year	Booked		Discovery well		Exploratory wells		All wells		Oldest 50% of wells		Section	
	Annual	Cum.	Annual	Cum.	Annual	Cum.	Annual	Cum.	Annual	Cum.	Annual	Cum.
1951	61.2	205.5	57.5	522.8	24.9	113.4	14.3	73.5	24.6	95.4	20.3	98.2
1952	87.8	293.3	145.8	668.6	58.7	172.1	21.0	94.5	42.9	138.3	44.0	142.2
1953	76.1	369.5	79.7	748.3	48.0	220.1	30.4	124.9	71.1	209.4	42.7	184.9
1954	58.8	428.3	147.3	895.6	86.5	306.6	81.7	206.6	47.4	256.9	30.7	215.6
1955	59.3	487.6	62.2	957.8	47.5	354.1	43.5	250.1	43.1	300.0	31.4	247.1
1956	64.5	552.2	72.3	1 030.1	47.9	401.9	27.0	277.1	74.9	374.9	47.7	294.8
1957	64.9	617.1	116.4	1 146.5	69.8	471.7	32.0	309.1	60.5	435.4	45.7	340.5
1958	110.4	727.5	80.9	1 227.4	99.8	571.5	46.2	355.2	79.1	514.4	51.5	392.0
1959	88.5	816.0	141.4	1 368.8	59.5	631.0	61.6	416.8	111.5	625.9	56.7	448.7
1960	119.9	935.9	53.3	1 422.0	63.9	694.8	71.3	488.1	114.1	739.9	83.9	532.5
1961	13.3	949.2	128.5	1 550.5	56.3	751.2	59.3	547.5	91.7	831.7	81.0	613.5
1962	49.7	998.9	66.6	1 617.1	40.6	791.7	48.4	595.8	72.3	904.0	62.4	676.0
1963	35.8	1 034.7	66.1	1 683.2	81.4	873.2	46.7	642.5	67.5	971.5	52.1	728.1
1964	85.9	1 120.6	34.8	1 718.0	47.0	920.1	41.9	684.4	69.4	1 040.9	60.0	788.0
1965	89.7	1 210.4	62.0	1 780.0	66.9	987.1	47.6	732.0	70.0	1 110.9	57.2	845.3
1966	40.6	1 251.0	29.8	1 809.8	42.5	1 029.6	37.1	769.1	58.9	1 169.8	57.8	903.0
1967	73.9	1 324.9	78.5	1 888.3	79.8	1 109.3	83.8	852.8	70.7	1 240.5	58.9	961.9
1968	134.6	1 459.5	36.2	1 924.5	65.9	1 175.2	53.3	906.1	91.2	1 331.7	84.5	1 046.5
1969	87.5	1 547.0	68.2	1 992.7	63.7	1 238.9	83.7	989.8	94.4	1 426.2	80.8	1 127.3
1970	46.2	1 593.2	39.0	2 031.7	48.5	1 287.3	58.8	1 048.6	92.9	1 519.1	84.6	1 211.9

TABLE K.1 (cont'd)

Year	Booked		Discovery well		Exploratory wells		All wells		Oldest 50% of wells		Section	
	Annual	Cum.	Annual	Cum.	Annual	Cum.	Annual	Cum.	Annual	Cum.	Annual	Cum.
1971	45.4	1 638.6	41.2	2 073.0	37.1	1 324.5	46.5	1 095.1	59.0	1 578.1	60.4	1 272.3
1972	45.2	1 683.9	58.9	2 131.9	56.4	1 380.9	65.0	1 160.0	87.9	1 666.0	78.0	1 350.3
1973	183.3	1 867.2	69.9	2 201.8	85.2	1 466.1	70.4	1 230.4	89.8	1 755.8	81.5	1 431.8
1974	147.0	2 014.3	93.2	2 294.9	71.7	1 537.7	75.4	1 305.8	90.6	1 846.4	86.6	1 518.4
1975	20.8	2 035.1	47.6	2 342.5	76.3	1 614.0	92.5	1 398.3	110.7	1 957.0	96.7	1 615.1
1976	105.6	2 140.7	105.0	2 447.5	157.6	1 771.7	135.4	1 533.6	167.2	2 124.2	126.2	1 741.3
1977	127.6	2 268.2	117.6	2 565.1	222.4	1 994.0	142.5	1 676.1	164.6	2 288.9	141.7	1 883.0
1978	163.3	2 431.6	108.3	2 673.4	189.6	2 183.7	138.5	1 814.6	151.6	2 440.5	158.6	2 041.6
1979	123.2	2 554.7	94.8	2 768.2	135.2	2 318.9	145.7	1 960.3	146.2	2 586.7	159.9	2 201.5
1980	92.4	2 647.1	101.5	2 869.8	168.5	2 487.4	180.4	2 140.6	167.6	2 754.3	185.2	2 386.7
1981	117.0	2 764.1	71.4	2 941.2	106.8	2 594.2	135.0	2 275.6	91.0	2 845.3	121.8	2 508.5
1982	118.7	2 882.8	37.9	2 979.1	80.5	2 674.7	109.6	2 385.2	61.4	2 906.7	85.4	2 594.0
1983	39.0	2 921.8	45.7	3 024.8	51.1	2 725.8	76.6	2 461.8	50.1	2 956.8	62.7	2 656.7
1984	40.5	2 962.3	35.8	3 060.6	75.5	2 801.3	93.0	2 554.8	47.6	3 004.4	82.3	2 739.0
1985	42.6	3 004.9	39.1	3 099.7	78.0	2 879.2	126.9	2 681.7	48.5	3 052.9	93.1	2 832.0
1986	21.8	3 026.7	50.6	3 150.4	57.9	2 937.2	93.4	2 775.1	51.1	3 104.0	80.5	2 912.5
1987	0.0	3 026.7	36.0	3 186.3	81.5	3 018.7	105.8	2 880.9	60.9	3 164.8	87.2	2 999.6
1988	64.6	3 091.3	49.0	3 235.3	121.1	3 139.8	149.2	3 030.2	60.7	3 225.5	114.5	3 114.2
1989	107.8	3 199.0	36.0	3 271.2	78.0	3 217.8	105.9	3 136.1	39.8	3 265.4	75.6	3 189.8
1990	87.8	3 286.8	34.6	3 305.8	73.2	3 290.9	120.7	3 256.8	36.7	3 302.1	83.9	3 273.7
1991	34.8	3 321.6	15.8	3 321.6	30.7	3 321.6	64.6	3 321.4	19.6	3 321.6	47.9	3 321.6

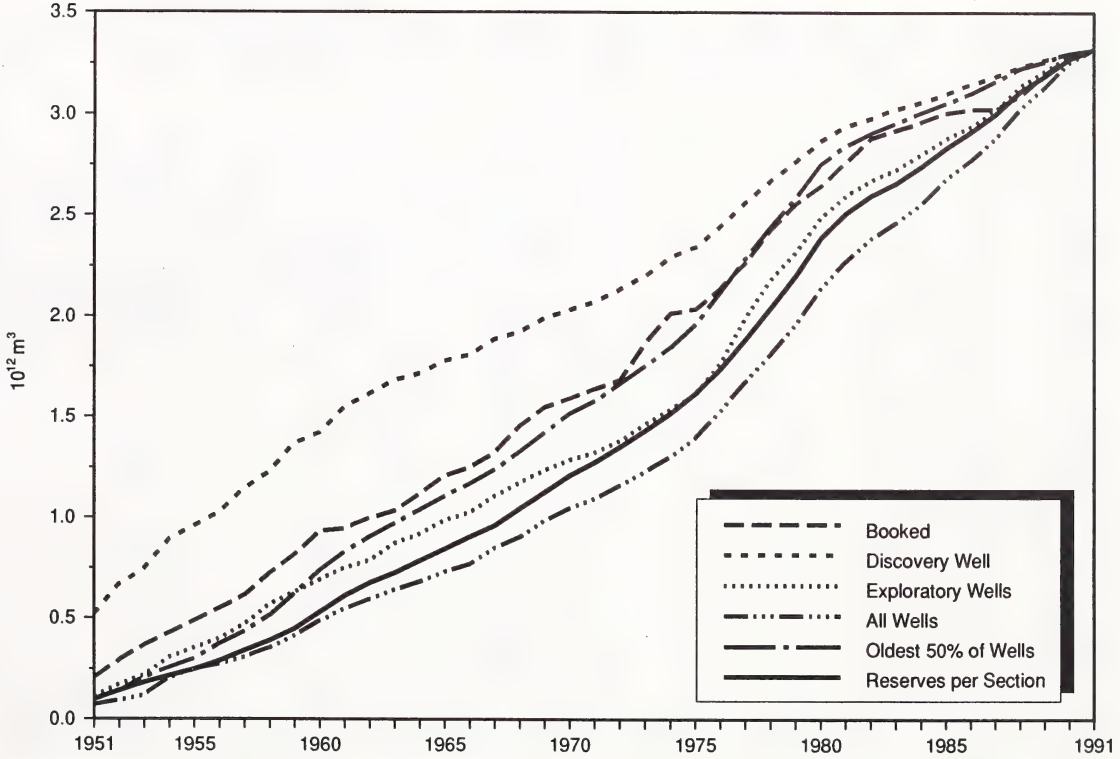


FIGURE K.1 HISTORICAL RESERVES GROWTH ANALYSIS TECHNIQUES

APPENDIX L DEMAND AND SUPPLY FORECASTS

This Appendix contains tables showing forecasts of expected demand for Alberta gas and the supply available to meet that demand. Table L.1 shows the demand and expected production from several categories of reserves. This table shows the year-by-year data for 15 years in 10^9 m^3 per year on a 37.4 MJ/m^3 basis.

The remaining tables contain pool-by-pool forecasts for several of the reserve categories. These pool forecasts are shown on an annual basis for the first ten years, 1992 to 2001, and the fifteenth year, 2006. All gas volumes are shown in 10^9 m^3 per day of 'as is' marketable gas.

TABLE L.1 Gas Demand and Supply
10^9 m^3 at 37.4 MJ/m^3

	Demand				Supply											
Year	Alberta	Ex-Alberta	Export	Total	Major	Cycling	Shallow	Solution	Injection	BER	Deferred	Other	Estab.	Trend	Total	Capacity
1992	27.7	30.7	42.6	101.0	13.6	8.7	7.5	7.0	0.6	0.0	0.0	62.6	100.0	1.0	101.0	123.8
1993	28.5	31.8	46.4	106.7	13.8	9.1	7.4	6.3	0.6	0.0	0.1	65.9	103.6	3.1	106.7	126.2
1994	29.3	32.4	47.8	109.5	13.5	8.6	7.3	5.8	0.5	0.1	0.2	67.4	104.0	5.5	109.5	128.1
1995	30.5	33.1	53.2	116.8	12.7	8.5	7.0	5.4	0.4	0.3	0.3	71.4	106.4	10.4	116.8	133.0
1996	31.6	33.6	53.4	118.6	11.9	7.7	6.7	5.1	0.4	0.6	0.3	70.8	104.1	14.5	118.6	137.7
1997	31.8	34.1	53.5	119.4	10.3	7.0	6.4	4.9	0.4	0.9	0.5	69.6	100.6	18.8	119.4	141.1
1998	32.7	34.6	53.6	120.9	9.8	6.9	6.1	4.7	0.3	1.2	0.6	66.3	96.5	24.4	120.9	139.9
1999	33.8	35.1	53.8	122.7	9.3	6.2	5.7	4.4	0.3	1.5	0.9	63.2	92.1	30.6	122.7	136.1
2000	35.4	35.7	54.0	125.1	8.6	5.8	5.3	4.1	0.3	1.9	0.9	60.6	88.1	36.9	125.0	133.9
2001	36.0	36.2	54.2	126.4	7.8	5.3	4.9	3.9	0.3	2.2	1.0	56.8	82.8	43.6	126.4	130.8
2002	36.8	36.8	54.4	128.0	7.2	4.8	4.5	2.0	0.3	2.3	1.0	52.4	75.1	50.3	125.4	125.4
2003	37.2	37.4	54.5	129.1	6.5	4.4	4.1	1.9	0.2	2.4	1.0	44.9	65.8	54.9	120.7	120.7
2004	38.5	38.0	54.7	131.2	5.8	3.1	3.8	1.6	0.2	2.4	1.0	38.3	56.6	58.7	115.3	115.3
2005	39.2	38.6	54.9	132.7	5.1	2.5	3.5	1.4	0.2	2.4	1.2	33.7	50.4	61.7	112.1	112.1
2006	39.8	39.3	55.0	134.1	4.5	2.3	3.2	1.3	0.2	2.4	1.3	29.3	44.7	64.0	108.7	108.7

TABLE L.2 Production from Major Gas Pools
10^3 m^3 per day

Field	Pool(s)	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2006
Blackstone	Beaverhill Lake A	1 749	1 821	1 810	1 871	1 839	1 900	1 836	1 736	1 562	1 395	868
Boyer	Bluesky A & Gething A	859	902	883	914	909	909	925	953	979	1 022	942
Brazeau River	Elkton-Shunda B	2 125	2 082	2 002	1 921	1 630	1 505	1 408	1 337	1 208	1 080	164
Caroline	Beaverhill Lake A	44	1 836	2 444	2 444	2 444	2 444	2 444	2 444	2 444	2 444	1 386
Cranberry	Slave Point A	1 178	1 283	1 346	1 465	1 531	1 406	1 325	1 255	1 118	998	569
Dunvegan	Debolt A, B, C & D	2 625	2 571	2 231	2 164	1 886	1 758	1 644	1 579	1 503	1 459	1 110
Elmworth	Falher MU #1	2 277	2 070	1 760	1 554	1 338	1 198	1 087	995	904	831	0
Hanlan	Beaverhill Lake A	3 286	3 488	3 466	3 599	3 503	3 590	3 291	3 060	2 698	2 380	1 421
Jumping Pound West	Rundle A & B	2 998	3 166	3 034	2 780	2 460	2 357	2 245	2 144	2 064	1 990	1 450
Jumping Pound West	Rundle C	1 273	1 238	1 131	1 062	963	895	850	819	788	770	618
Karr	Bluesky A	850	892	956	1 051	1 164	1 187	1 244	1 151	1 051	974	610
Leduc-Woodbend	D-3 A	2 975	2 975	2 975	2 975	2 975	0	0	0	0	0	0
Leismer	Clearwater A	2 964	3 094	2 588	2 277	1 941	1 720	1 560	1 432	1 310	1 217	0
Liege	Mann-Devonian MU #1	3 584	2 361	2 463	222	218	218	221	181	72	7	0
Marten Hills	Wabiskaw A & Wabamun A	1 985	1 451	1 389	1 552	1 251	1 066	946	836	678	0	0
Provost	Viking CAK & Mann E	1 128	1 060	997	937	881	827	778	732	688	657	504
Sinclair	Doig A	1 280	1 338	1 316	1 308	1 162	1 078	1 029	995	914	836	568
Twining	L Mann A & Rundle A	725	796	850	949	1 066	983	935	904	824	746	403
Viking-Kinsella	U&M Vik A & U Mann YY	1 160	1 176	1 083	1 042	966	917	887	868	847	840	705
Westerose South	Glauc A & Bsl Quartz F	2 172	2 269	2 245	2 329	2 045	1 903	1 821	1 767	1 625	1 436	600
Wizard Lake	D-3 A	0	0	0	250	357	385	376	355	344	348	348
Total		37 237	37 869	36 969	34 666	32 529	28 246	26 852	25 543	23 621	21 430	12 266

TABLE L.3 Production from Cycling Pools
10^3 m^3 per day

Field	Pool(s)	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2006
Bigstone	D-3 A	302	287	272	259	246	233	222	211	200	190	147
Bonnie Glen	D-3 A	887	813	740	2 072	1 997	1 871	3 504	3 235	3 235	3 176	0
Brazeau River	Nisku F	0	0	0	0	111	111	111	111	111	111	66
Brazeau River	Nisku J	168	143	119	107	96	83	66	56	45	29	0
Brazeau River	Nisku K	0	0	0	255	256	257	239	195	151	114	0
Brazeau River	Nisku M	0	0	0	0	0	325	340	298	249	213	115
Brazeau River	Nisku P	997	1 001	972	1 012	1 070	1 113	1 151	1 181	1 201	1 225	1 020
Brazeau River	Nisku S	242	242	242	242	241	240	237	233	228	107	0
Carson Creek	Beaverhill Lake B	554	436	326	253	163	133	107	85	69	56	0
Carstairs	Elkton A	384	362	482	415	424	439	441	361	302	193	144
Crossfield	Rundle A	474	518	501	482	463	447	422	403	384	364	274
Golden Spike	D-3 A	0	0	0	0	0	0	0	0	0	0	0
Harmattan East	Rundle	1 970	2 260	2 167	1 932	1 723	1 537	1 370	1 222	1 090	973	548
Harmattan-Elkton	Rundle C	2 833	3 288	3 678	3 678	3 678	2 610	2 212	1 751	1 576	1 203	468
Kakwa	Cardium A	0	0	0	0	0	0	0	0	532	532	532
Kaybob	Beaverhill Lake C	18	14	10	7	4	3	3	3	3	3	275
Kaybob South	Beaverhill Lake A	12 257	11 744	10 165	8 504	7 239	6 009	4 930	4 146	3 342	2 778	996
Lookout Butte	Rundle A	0	124	116	106	96	89	82	75	68	61	0

TABLE L.3 (cont'd)
10^3 m^3 per day

Field	Pool(s)	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2006
Ricinus	Cardium A	540	1 260	1 170	1 350	900	810	780	780	780	780	780
Ricinus	Cardium QQQ	60	140	130	150	100	90	87	87	87	87	87
Valhalla	Halfway B	122	122	122	132	141	150	160	160	169	178	225
Watertön	Rundle-Wabamun A	805	1 205	1 463	1 595	1 636	1 518	1 386	1 266	1 096	1 014	570
Wembley	Halfway B	100	100	100	108	115	123	131	131	138	146	184
Westerose	D-3	240	240	240	240	240	855	855	855	855	855	0
Westerose South	D-3 A	88	46	24	13	0	0	0	0	0	0	0
Westpem	Nisku E	213	155	138	125	12	0	0	0	0	0	0
Windfall	D-3 A	586	403	294	194	78	0	0	0	0	0	0
Total		23 840	24 903	23 471	23 231	21 029	19 046	18 836	16 845	15 911	14 388	6 431

TABLE L.4 Production from Southeastern Alberta Shallow Gas Pools
10^3 m^3 per day

Field	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2006
Alderson	2 322	2 182	2 049	1 928	1 812	1 703	1 601	1 505	1 415	1 330	976
Atlee-Buffalo	337	385	437	489	523	523	523	491	462	434	319
Bantry	1 311	1 197	1 074	941	817	713	599	513	418	342	86
Bassano	1	1	2	2	2	2	3	3	3	3	3
Berry	2	3	4	6	6	6	6	6	6	6	6
Bindloss	55	65	78	94	112	127	138	138	138	129	95
Bow Island	10	21	34	51	69	84	91	91	91	91	91
Brooks	42	36	31	27	22	18	15	12	10	9	0
Cassils	101	118	143	169	201	232	257	257	257	257	201
Cessford	931	1 017	1 088	1 104	1 104	1 104	1 104	1 104	1 104	1 037	761
Connorsville	51	76	108	144	186	226	256	256	256	256	256
Countess	437	561	703	874	1 074	1 264	1 410	1 410	1 410	1 410	1 325
Estuary	43	41	33	25	18	13	10	0	0	0	0
Eyremore	4	6	9	11	15	19	22	22	22	22	22
Gleichen	109	100	86	73	60	48	37	29	23	19	0
Hussar	141	163	192	222	255	283	305	305	305	305	254
Jenner	361	390	418	447	475	475	475	475	475	447	328
Johnson	6	12	20	28	34	41	47	47	47	47	47
Kitsim	19	29	39	39	39	39	39	39	39	39	39
Lathom	11	17	24	24	24	24	24	24	24	24	24
Leckie	19	24	30	36	43	48	53	53	53	53	50
Matziwin	225	238	254	272	285	285	285	285	285	268	197

TABLE L.4 (cont'd)

Field	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2006
Medicine Hat	5 510	5 035	4 560	4 085	3 610	3 183	2 755	2 375	2 043	1 758	665
Newell	73	75	77	79	81	81	81	76	71	67	48
Princess	1 235	1 235	1 161	1 092	1 026	964	906	852	801	752	552
Ronalane	1	2	2	2	2	2	2	2	2	2	2
Seiu Lake	29	43	57	57	57	57	57	57	57	57	57
Suffield	6 133	6 033	5 748	5 273	4 750	4 275	3 800	3 278	2 850	2 494	903
Verger	884	960	1 045	1 140	1 235	1 235	1 235	1 235	1 235	1 161	852
Wayne-Rosedale	52	81	111	111	111	111	111	111	111	111	111
Wintering Hills	119	181	252	318	385	461	519	519	519	519	519
Total	20 574	20 327	19 869	19 163	18 433	17 646	16 766	15 570	14 532	13 449	8 789

TABLE L.5 Production from Major Solution Gas Pools
10^3 m^3 per day

Field	Pool(s)	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2006
Alexis	Banff A	13	12	11	11	10	10	10	9	8	8	6
Bantry	Mannville A	48	38	31	24	20	0	0	0	0	0	0
Brazeau River	Nisku G	1	1	1	1	1	1	1	1	1	0	0
Brazeau River	Nisku I	22	19	16	14	12	10	8	0	0	0	0
Carson Creek North	Beaverhill Lake A & B	231	209	189	171	157	145	131	117	104	95	56
Cessford	Mannville C	46	42	37	34	30	27	25	0	0	0	0
Clive	D-2 A	32	29	26	23	21	19	17	16	14	13	0
Duhamel	D-3 B	3	3	0	0	0	0	0	0	0	0	0
Ferrier	Cardium D	82	77	72	67	64	60	55	51	48	44	31
Ferrier	Cardium E	107	99	93	86	82	76	71	66	61	57	40
Ferrier	Cardium G & L	160	148	136	126	116	107	100	94	87	79	52
Garrington	Cardium A & B	12	10	9	8	7	6	6	5	4	4	2
Garrington	Mannville B	101	88	74	61	54	47	41	34	0	0	0
Garrington	Wabamun A	34	32	29	27	25	24	23	0	0	0	0
Glenpark	D-3 A	4	4	4	4	3	3	3	3	3	2	2
Innisfail	D-3	61	50	41	34	29	25	20	17	12	0	0
Joarcam	Viking	65	55	46	39	32	28	23	19	16	14	0
Joffre	D-2 A	18	17	16	15	14	14	13	13	12	11	0
Kaybob	Beaverhill Lake A	228	194	165	140	119	102	86	74	62	53	23
Kaybob	Beaverhill Lake B	16	16	16	16	16	15	14	13	12	12	7
Kaybob South	Triassic A	124	114	105	98	90	83	77	72	67	61	40

TABLE L.5 (cont'd)
10^3 m^3 per day

Field	Pool(s)	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2006
Leduc-Woodbend	D-2 A	4	3	0	0	0	0	0	0	0	0	0
Leduc-Woodbend	D-3 A	20	18	15	13	11	9	8	0	0	0	0
Medicine River	Glauconitic A	37	33	29	26	22	20	18	15	14	12	6
Mitsue	Gilwood A	323	292	264	239	216	196	177	163	149	135	0
Provost	Viking C	9	9	8	7	7	6	6	6	6	6	4
Rainbow South	Keg River E	11	10	10	9	9	8	8	8	7	7	5
Rainbow South	Keg River G	3	2	2	2	2	2	1	1	1	0	0
Ricinus	Cardium W	15	15	15	15	15	15	14	13	12	11	0
Rowley	Pekisko A	8	8	8	8	7	7	6	6	6	5	4
Snipe Lake	Beaverhill Lake	14	13	12	12	11	10	10	10	9	9	7
Swan Hills	Beaverhill Lake C	36	34	33	31	30	28	27	26	24	23	18
Swan Hills South	Beaverhill Lake A & B	131	123	116	108	100	92	86	81	75	70	48
Sylvan Lake	Pekisko B	44	44	44	44	39	34	29	25	22	18	10
Twining	L. Mann A & Rundle A	173	162	153	144	137	129	122	114	107	101	74
Utikuma Lake	Keg River Sand A	22	18	15	12	10	0	0	0	0	0	0
Virginia Hills	Beaverhill Lake	98	98	98	89	79	70	62	55	49	43	23
Willesden Green	Cardium A	99	95	92	88	85	81	78	75	72	69	57
Wimborne	D-3 A	109	90	76	63	0	0	0	0	0	0	0
Total		2 564	2 324	2 107	1 909	1 682	1 509	1 376	1 202	1 064	962	515

TABLE L.6 Production from Injection Pools
10^3 m^3 per day

Field	Pool(s)	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2006
Acheson	D-3 A	34	23	16	0	0	0	0	0	0	0	0
Ante Creek	Beaverhill Lake	46	44	42	41	39	38	36	34	34	32	26
Bellshill Lake	Blairmore	40	29	0	0	0	0	0	0	0	0	0
Brazeau River	Nisku A	36	27	20	0	0	0	0	0	0	0	0
Brazeau River	Nisku B	17	15	14	12	11	10	9	8	7	0	0
Brazeau River	Nisku D	29	26	23	21	19	17	15	0	0	0	0
Brazeau River	Nisku E	56	42	31	23	17	12	10	8	7	5	0
Caroline	Cardium E	71	60	50	43	36	30	25	20	17	0	0
Fenn-Big Valley	D-2 A	8	5	0	0	0	0	0	0	0	0	0
Goose River	Beaverhill Lake A	35	33	31	28	26	24	22	20	19	17	0
Judy Creek	Beaverhill Lake A	135	126	118	110	102	95	89	83	77	72	50
Judy Creek	Beaverhill Lake B	74	68	62	57	52	48	43	40	37	34	22
Nipisi	Gilwood A	114	104	94	85	77	70	63	57	51	47	29
Pembina	Belly River I	9	9	9	9	9	9	8	8	7	7	4
Pembina	Cardium	447	428	410	392	374	357	341	325	311	297	236
Pembina	Key Belly River X	5	5	5	5	5	5	5	5	5	5	5
Rainbow	Keg River A	44	34	27	21	0	0	0	0	0	0	0
Rainbow	Keg River B	12	10	8	6	5	4	0	0	0	0	0
Rainbow	Keg River F	56	50	46	41	37	34	31	28	25	23	14
Rainbow	Keg River O	12	11	10	9	8	8	7	6	5	5	3
Rainbow	Keg River AA	16	16	15	14	13	13	12	11	11	10	0
Rainbow South	Keg River B	22	20	19	18	16	15	13	13	12	11	0
Ricinus	Cardium L	9	9	9	9	9	9	9	9	9	9	6
Simonette	D-3	36	29	24	19	16	0	0	0	0	0	0
Swan Hills	Beaverhill Lake A & B	244	231	220	209	198	189	179	170	162	153	119
Wizard Lake	D-3 A	69	55	44	35	28	23	18	0	0	0	0
Total		1 676	1 509	1 347	1 207	1 097	1 010	935	845	796	727	514